at www.prepa.com. Neither this report nor any additional information on the Authority's website is deemed to be part of or incorporated by reference in this Official Statement.

Ernst & Young LLP has been engaged to audit the Authority's financial statements for fiscal year 2012.

Subsidiaries

Pursuant to the Act, the Authority is authorized to create subsidiaries in order to, among other things, delegate or transfer any of its rights, powers, functions or duties. The Authority currently has five principal subsidiaries organized in a holding company structure. Currently, only one of the Authority's subsidiaries has significant operations.

PREPA Holdings, LLC, a wholly-owned subsidiary of the Authority, was created for the sole purpose of acting as a holding company and has no current operations. PREPA Holdings, LLC is the direct parent of the following entities: PREPA Networks, LLC, also known as PREPA.net; PREPA Utilities, LLC; PREPA Oil & Gas, LLC; and InterAmerican Energy Sources, LLC.

In 2002 the Authority completed the installation of a Backbone Fiber Optic Cable System which has modernized its internal communications by providing faster and more secure data transmission for operations, load management, system protection and security. This fiber optic system consists of a 663 mile fiber optic telecommunications network of which 386 miles are for the Authority's use and 277 miles are for the use of PREPA.net. The system is installed on the Authority's rights-of-way (mainly its transmission lines) and was financed through the issuance of $43.7 million aggregate principal amount of subordinate obligations.

In addition to the Backbone Fiber Optic Cable System, the Authority has installed a Distribution Fiber Optic Cable System that consists of 691 miles of fiber optic cables, of which 399 miles are for the Authority's and PREPA.net's use and 292 miles are for the exclusive use of PREPA.net. The Authority created PREPA.net in order to commercially exploit the excess fibers of the installed fiber optic cable system. PREPA.net markets the excess communication capacity of the Authority's fiber optic cable system. PREPA.net currently offers next generation telecommunications services to carriers, internet service providers, and large commercial enterprises. These services include data transmission via Synchronous Optical Network (SONET), metro and long haul Ethernet transport services, wireless last mile, and internet protocol services optimized for voice over internet protocol. PREPA.net also offers international fiber optic cable capacity and satellite teleport facilities through the submarine fiber optic cable capacity acquired in 2008. As of June 30, 2011, PREPA.net had total assets of $27.9 million and total liabilities of $18.1 million. PREPA.net's change in net assets for fiscal year 2011 was $3.8 million. PREPA.net has a term loan with a commercial bank with an outstanding principal balance of $9.8 million as of June 30, 2011 and, as of that date, owed the Authority approximately $3.7 million for advances made by the Authority in the ordinary course of business. PREPA.net continues to add customers to its portfolio and the Authority continues with the installation of fiber optic cables. The Authority expects that the commercial exploitation of the fiber optic system will provide a new source of revenues to its operations that will ultimately benefit its electric energy customers.

PREPA Utilities, LLC, was created for the purpose of investing, financing, constructing and operating industrial projects and other infrastructure relating to the optimization of the Authority's electric infrastructure. PREPA Oil & Gas, LLC, was created for the purpose of buying, selling, exchanging and otherwise trading or dealing with the export, import, manufacture, production, preparation, handling, storage, and distribution of oil and gas and any other fuels required to satisfy the Authority's power generation needs. Finally, InterAmerican Energy Sources was created for the purpose

of investing, developing, financing, constructing and operating renewable energy projects and other infrastructure related to the optimization of the Authority's electric infrastructure. PREPA Utilities, LLC, PREPA Oil & Gas, LLC, and InterAmerican Energy Sources, LLC are currently not operating.

Fiscal Oversight Agreement

The Authority and Government Development Bank, as fiscal agent for the Authority, entered into a Fiscal Oversight Agreement, dated as of July 1, 2009, as amended (the "Fiscal Oversight Agreement"), pursuant to which the Authority agreed to implement a comprehensive expense reduction program, including certain fiscal oversight controls, subject to laws and existing agreements of the Authority, and provide Government Development Bank with certain financial information and operating data, as well as other financial information reasonably requested by Government Development Bank. The Fiscal Oversight Agreement is intended to allow the Authority to become self sufficient and to protect and improve the credit rating of the Authority, so that the Authority may obtain adequate financing to fund its capital expenditure requirements and operate the Systems in an efficient and reliable manner and in compliance with applicable laws and regulations and other regulatory requirements.

THE SYSTEM

The Authority is the supplier of virtually all of the electric power consumed in the Commonwealth. As of December 31, 2011, the Authority served approximately 1.5 million clients, representing a population of approximately 3.7 million.

Generating Facilities

As of June 30, 2011, investment in Authority-owned production plant in service totaled approximately $4.1 billion based on original installed cost, the total nameplate rating of the Authority-owned generating facilities of the System was 4,937 MW and their total dependable generating capacity was 4,878 MW. In addition, the Authority purchases power under long-term power purchase agreements from two cogeneration facilities: EcoEléctrica and AES-PR. Under its agreement with EcoEléctrica, it has the right to purchase 507 MW of net dependable generating capacity. Under its agreement with AES-PR, it has the right to purchase 454 MW of net dependable generating capacity. The Authority has dispatch control over both facilities, and their output is fully integrated into the System.

Existing Generating Facilities (in MW)

Generating Plants	Nameplate Rating (82 Units)	Dependable Generating Capacity					
		Total (82 Units)	Steam (16 Units)	Combined Cycle Power Blocks (13 Units)	Combustion Turbine (25 Units)	Hydro (21 Units)	Other (7 Units)
Aguirre	1,554	1,534	900[1]	592[2]	42[3]	-	-
Costa Sur	1,030	1,032	990	-	42[3]	-	-
Palo Seco	731	728	602	-	126[4]	-	-
San Juan	870	840	400	440[5]	-	-	-
Mayagüez	220	220	-	-	220[6]	-	-
Arecibo	248	248	-	-	248[7]	-	-
Other Locations	284	276	-	-	168[8]	100	8[9]
Subtotal	4,937	4,878	2,892	1,032	846	100	8
Peñuelas – EcoEléctrica	507	507	-	507[10]	-	-	-
Guayama – AES-PR	454	454[11]	454[11]	-	-	-	-
Renewable – Windmar	2[12]	-	-	-	-	-	-
Total	5,900	5,839	3,346	1,539	846	100	8

(1) Consists of the Authority's two largest units, Aguirre Units 1 and 2, each with a dependable generating capacity of 450 MW.
(2) Consists of two combined-cycle power blocks, each made up of four 50 MW combustion turbine units and one 96 MW steam-turbine unit.
(3) Consists of two 21 MW units.
(4) Consists of six 21 MW units.
(5) Consists of two combined cycle power block, each made up of one 160 MW combustion turbine unit and one 60 MW steam-turbine unit.
(6) Consists of four 55 MW units.
(7) Consists of three 83 MW units.
(8) Consists of eight 21 MW units.
(9) Consists of five diesel units in the Municipality of Culebra and two in the Municipality of Vieques with an aggregate dependable capacity of approximately 8 MW held on standby reserve.
(10) Consists of one combined cycle power block, made up of two 165 MW combustion turbine units and a 177 MW steam turbine unit.
(11) Consists of two 227 MW units.
(12) Consists of photovoltaic energy.

The EcoEléctrica plant is a cogeneration facility located in the Municipality of Peñuelas. The facility includes a combined cycle power block, consisting of one steam and two combustion turbine units, and a liquefied natural gas terminal. The Authority began purchasing power from EcoEléctrica in September 1999 during the testing and start-up phase of the facility. Commercial operation began in March 2000. The Authority entered into an agreement with EcoEléctrica to purchase all of the power produced by the facility for a term of 22 years from the date of commencement of commercial operation. The agreement requires EcoEléctrica to provide 507 MW of dependable generating capacity to the Authority. The Authority may purchase any energy produced by the facility in excess of 507 MW, if made available, by paying an energy charge only. No capacity charge would be imposed on the Authority for this "excess" power. EcoEléctrica has entered into a long-term supply agreement to meet its expected needs for natural gas at the facility.

The power purchase agreement with EcoEléctrica includes monthly capacity and energy charges to be paid by the Authority for the 507 MW of capacity, which EcoEléctrica is committed to provide. The capacity charge is subject to reduction, progressively to zero, if the facility does not achieve certain availability guarantees determined on a 12-month rolling average basis. The energy charges for power purchases are based on a number of factors including a natural gas related charge on a per kWh of energy basis and inflation indices. The EcoEléctrica purchased power costs incorporate a minimum monthly power or fuel purchase requirement based on an average capacity utilization factor on the part of the Authority. After paying this minimum requirement, the Authority only pays for energy actually received (including energy in excess of the 507 MW guaranteed by EcoEléctrica). This element of the agreement, when combined with the possible reduction in the capacity charge described above, effectively transfers substantially all of the economic risk of operating the facility to EcoEléctrica.

The AES-PR plant is a co-generation facility located in the Municipality of Guayama. Commercial operation began in November 2002. This clean burning coal technology facility consists of two identical fluidized bed boilers and two steam turbines with 454 MW of dependable generating capacity. The Authority entered into an agreement with AES-PR to purchase all of the power produced by this facility for a term of 25 years from the date of commencement of commercial operation. The contract with AES-PR is substantially similar to the EcoEléctrica contract described above, including the compensation structure. Above a certain minimum amount, the Authority is only obligated to purchase energy actually produced by the facility. AES-PR is an affiliate of AES Corporation.

The AES-PR and EcoEléctrica projects contribute to the Authority's efforts towards fuel diversification and improved reliability of service. Prior to the commencement of operations of the EcoEléctrica and AES-PR facilities, oil-fired units produced approximately 99% of the Authority's energy. After the incorporation of the EcoEléctrica and AES-PR facilities to the System, approximately 31% of the Authority's annual energy generation is being provided by non-oil-fired generating facilities.

Among other benefits, the integration of the EcoEléctrica and AES-PR cogeneration facilities into the Authority's System reduces the impact of changes in energy costs to the Authority's clients resulting from short-term changes in fuel costs due to the manner of calculation of the energy charges under the EcoEléctrica and AES-PR agreements. While the agreements provide that energy charges will change based on different formulas relating to the prior year, each agreement fixes the energy price for each year of the contract at the beginning of such year. Fixing the energy component of the price for the whole year reduces the impact of seasonal or short duration variations in the market price of electricity. Because the energy price is fixed and known for the entire year, the Authority is able to achieve better economic dispatching and scheduling of maintenance outages of all of its generating units. In addition, the year delay in the effect of energy price changes for these two facilities on the Authority's energy costs reduces variations of the fuel and purchased power components in the price of electricity sold by the Authority by postponing the impact of the price changes and bringing these changes out of step with price changes in the other components of the Authority's fuel mix.

All of the Authority's purchased power costs under the EcoEléctrica and AES-PR power purchase agreements are accounted for as operating expenses on the Authority's financial statements, are treated as a Current Expense under the Trust Agreement, and are being recovered by the Authority pursuant to the purchased power charge under its current rate structure.

Transmission and Distribution Facilities

The Authority's transmission and distribution system interconnects its power plants with major switching and load centers throughout Puerto Rico in order to allow the flow of power to and between these locations. The System is integrated and each generating unit is able to provide electric power to the transmission and distribution system.

Since the early 1990's, a substantial portion of the Authority's capital improvement program was directed at (i) improving its generating units in order to extend their life and increase their availability, thereby improving the System's equivalent availability, and (ii) expanding its generating capacity to improve its quality of service and meet forecasted increases in demand. As a result of the recent trends in demand, however, the Authority believes that it has sufficient capacity to meet current and future demand. Consequently, it has refocused its capital improvement program towards maintaining its existing generating units, converting its existing units into natural gas fired generation units and improving its transmission and distribution network in order to enhance reliability and improve efficiency. The Authority expects this shift in its capital improvement program to result in a marked improvement in its

economic dispatch schemes, energy transfer and transmission system losses, reliability, system security margins, voltage stability and system performance during double contingencies.

During the period from fiscal year 2007 to fiscal year 2011, the Authority invested $1.2 billion (or 46.4% of its capital improvement program) in its transmission and distribution system. The capital improvement program for the five fiscal years ending June 30, 2016 includes $811 million (or 48% of such program) for transmission and distribution facilities.

Transmission Facilities

As of June 30, 2011, the Authority's transmission plant in service totaled $2.0 billion based on original installed cost. The capital improvement program for the five fiscal years ending June 30, 2016 includes $407 million, or 24% of total capital improvement program, for extensions and improvements to transmission lines. As of December 31, 2011, the Authority had 2,450 circuit miles of transmission lines, consisting of 364 circuit miles of 230 kV lines, 710 circuit miles of 115 kV lines and 1,375 circuit miles of 38 kV lines. The Authority has 30 miles of underground 115 kV cable, 60 miles of underground 38 kV cable and 55 miles of submarine 38 kV cable to the islands of Vieques and Culebra. The Authority also has 175 transmission and distribution switchyards and 129 transmission substations located at generating sites and at other sites throughout the island with a total transformer capacity of 18,535,250 kilovolt amperes ("kVA"). In addition, the Authority has 20 portable substations with a total capacity of 289,600 kVA and two capacitor banks with a total capacity of 36,000 kVar for substation maintenance without service interruptions.

As part of the Authority's refocused capital improvement program, it is constructing two new 230 kV transmission lines to complement the transmission loops in the center and western parts of Puerto Rico. These two 230 kV transmission lines will connect one of the Authority's principal generation complexes in the south with major switching and load centers in the northern and central parts of the island. The first project consists of a 38-mile long 230 kV transmission line between the South Coast steam plant and the switchyard at the Cambalache gas turbines plant. The first stage of this project consists of the reconstruction and conversion to 230 kV of an existing 115 kV circuit line between the South Coast Steam Plant and Dos Bocas hydroelectric power plant. The second stage of the project consists of the construction of a new 230 kV line from Dos Bocas to the Cambalache facilities. The construction of this project is expected to be completed during fiscal year 2014. The Authority is also constructing a new 50-mile long 230 kV transmission line between its South Coast steam plant and the transmission center in Aguas Buenas. The construction of this new transmission line is expected to be completed during fiscal year 2016. Once in operation, these major infrastructure projects will significantly enhance the reliability and security margins of the transmission system, and will permit the increase of power transfers from the south coast of Puerto Rico to the northern, central and western regions. During fiscal year 2012, the Authority completed the conversion to 230 kV of the existing 115 kV circuit line from Costa Sur to the Ponce transmission center. The Authority also completed the conversion of the fuel oil fired boilers of Costa Sur Units 5 and 6 to units that will be able to use either oil or natural gas by April 2012.

The Authority has completed an underground 115 kV transmission circuit line around the San Juan metropolitan area in order to reduce power loss incidents in the aftermath of hurricanes and other major storms which strike Puerto Rico from time to time. The program to improve the 38 kV sub-transmission system continues in effect, including the construction of underground 38 kV lines in Carolina, Guaynabo and San Juan. Construction of the underground 38 kV lines in Vega Baja and Mayagüez has been completed. In addition, major reconstruction projects of aerial 38 kV lines in the central and western part of the island will significantly improve the reliability of the sub-transmission system.

During fiscal year 2009, the Authority commenced operations of the Palo Seco Gas Insulated Switchgear ("GIS"), one of the Authority's major gas insulated 115/38 kV switchyards with direct interconnection to 600 MW of generating capability, and a 90 MVARS Static Var Compensator (SVC) at the 38 kV bus of Bayamón Transmission Center, which improves the System's dynamic reactive power response to major contingencies and outages in the generation or transmission system. The Authority also commenced the operation of a new air insulated 38 kV switchyard in the municipality of Cidra, which improves the reliability and efficiency of the System while increasing its power transfer capability and improving voltage regulation of the sub-transmission system under normal conditions and contingency situations. Finally, the Authority completed the installation of a new 115 kV capacitor bank in the Juncos transmission center, which is intended to improve the voltage regulation in major load centers, increase the transmission system's power factor and reduce its reactive power losses. During fiscal year 2010, the Authority commenced operations of a new air insulated 38 kV switchyard in Aguadilla.

During fiscal year 2012, the Authority expects to commence operations of a new 115 kV capacitor bank in the Canóvanas transmission center in order to continue improving the voltage regulation in major load centers, increase the transmission system's power factor and reduce its reactive power losses. The Authority also expects to complete a new 150 megavolt ampere ("MVA") 115/38 kV transmission center in the municipality of Bayamón (Hato Tejas TC), as well as major expansion projects that add 150 MVA of 115/38 kV transforming capacity in the transmission centers of Canóvanas. A new 450 MVA 230/115 kV transmission center in Ponce TC, as well as an expansion project to add 150 MVA of 115/38 kV transforming capacity to existing facilities were in operation during fiscal years 2011 and 2012.

The Authority expects that the San Juan GIS 38 kV and 115 kV switchgears will enter into service in fiscal year 2014 and 2016, respectively. This will be one of the Authority's major gas insulated 115/38 kV switchyards with direct interconnection through the existing air insulated 115 kV bus to approximately more than 850 MW of generating capability.

Distribution Facilities

Investment in distribution plant in service as of June 30, 2011 totaled $3.3 billion based on original installed cost. The capital improvement program for the five fiscal years ending June 30, 2016 includes $404 million (or 24% of the total) for extensions and improvements to existing distribution lines to serve new clients and substations for accommodating new load growth areas. As of December 31, 2011, the electric distribution system included approximately 32,633 circuit miles of primary and secondary distribution lines and 1,139 distribution substations (806 are client-owned) with a total installed transformer capacity of 8,202,920 kVA.

The construction of new distribution substations is expected to improve the capacity and reliability of the Distribution System. Recently, the increase in capacity of Buen Pastor I 13.2 kV substation was energized at Guaynabo. The Juan Martín 13.2 kV (Yabucoa) and Santa Isabel 13.2 kV substations have been energized. Recently, the Mora TC 13.2 kV substation was energized at Arecibo. The Factor 13.2 kV substation at Arecibo is currently in the commissioning process. Moreover, the new 13.2 kV distribution substation at Río Bayamón II is under construction. This substation is expected to enter into service during fiscal year 2012.

Operations

The Authority has digitized all the transmission and distribution facilities into a geographic information system. This allows the Authority to create a common database for all its transmission and distribution facilities.

The Authority's data management system integrates a work management system, a geographic information system and an outage management system that is known by its Spanish acronym of AIRe. The AIRe system is structured to maintain its databases as well as interface with existing computerized systems in other Authority divisions such as finance, human resources, and payroll. This integration enables the Authority to track all work from initiation to completion through the same system, while keeping all geographic information (such as maps) updated with necessary additions and modifications. Some of the AIRe system benefits include improved client service, reduced operations and management expenses, improved emergency response, better planning, improved and consistent engineering/design and estimating practices, archived maintenance records and real-time system status reporting. The work management system of the AIRe system has been in service in all of the Authority's districts since 2001.

The Authority also expanded its satellite-based vehicle locator system from 107 to 747 vehicles in order to improve the service fleet's efficiency. In addition, the Authority is in the process of upgrading its asset and work management system and implementing an automatic service outage detection system.

The Authority has also implemented energy theft recovery initiatives that resulted in theft-related billings of approximately $27 million during fiscal year 2011 and collections of approximately $13.4 million. As part of these initiatives, the Authority is in the process of deploying "smart grid" technology by replacing its current automated meter reading system with new "smart meters" that allow the Authority to identify areas where theft is prevalent, include more robust anti-tampering technology and permit service to be remotely shut off. The Authority has also significantly increased its theft detection and prevention program by using comparison of local/temporary meters on the distribution lines versus the aggregate of the served meters, a comparison of a client's present electricity usage versus historical data, and a toll free hotline for anonymous reporting of suspected electricity theft. The Authority expects that these initiatives will result in $25 million of annual revenues for fiscal year 2012 and $30 million of annual revenues for fiscal years 2013 through 2016. The actual results from the theft recovery program may differ from the Authority's projections.

The Authority regularly reviews and upgrades its operating and maintenance practices, with an emphasis on improving the reliability of its transmission and distribution system. In order to improve the productivity of its transmission and distribution employees, the Authority has instituted programs to assist them in both technical and supervisory training. In addition, as part of its continuous effort to improve service quality, the Authority has acquired new software applications and trained its personnel for the analysis and monitoring of power quality.

The Consulting Engineers are of the opinion that the Authority's production plant and transmission and distribution system are in good repair and sound operating condition. See Appendix III—*Letter of the Consulting Engineers.*

Adequacy of Capacity

General

Electric utilities provide reliable service by establishing a level of dependable generating capacity that is at least equal to their load plus a reserve sufficient to allow for scheduled maintenance, forced or

unscheduled outages (defined below), reductions in generating capacity due to partial outages, and other unforeseen events. Unlike most electric utilities in the United States, which are able to purchase power from neighboring systems in the event of unscheduled outages of generating units or temporary surges in demand, the Authority, as an island utility, is not able to do so. In addition, the absence of significant seasonal variations in demand results in a relatively high load factor (approximately 75.8% in fiscal year 2011), which affords the Authority less flexibility to schedule maintenance. Therefore, the Authority must have greater total reserve capacity than other utilities in the United States to cover instances of generating unit outages.

The Authority's program to extend the life and increase the availability of its generating units has three components: formal operator training, comprehensive preventative maintenance, and design modification. The formal operator training part emphasizes safety, operating efficiency, and equipment integrity. The comprehensive preventative maintenance part of the program requires the Authority to remove all major generating units from service for maintenance at regularly scheduled intervals to ensure their reliability ("scheduled outages"). The design modification part of the program represents the Authority's commitment to improve the operation of generating units by installing redesigned, improved components, or by undertaking conversions of such generating units, in order to reduce the risk of units being forced out of service or being forced to operate at partial output ("forced or unscheduled outages"). About half of the $1.2 billion in capital expenditures for the five fiscal years ended June 30, 2011 for production plant was spent for such scheduled maintenance program.

The Authority maintains some generating capacity as a reserve (referred to as a "controlled reserve") for frequency quality, in anticipation of unscheduled outages or other unforeseen events. The Authority controlled reserve criterion is 200 MW, but in order to maintain it, more than 500 MW of spinning reserve was needed. Based on its experience, however, the Authority implemented improvements in the System that allowed it to reduce its spinning reserve requirements while continuing to provide reliable service to clients and reducing its fuel cost.

In December 2006, a fire at the Authority's Palo Seco plant damaged one of the four oil-fired generating units. In a separate incident, a fire also damaged the control room that controls all four generating units. The Authority returned the first of the four Palo Seco units to service in November 2007. As of the end of the first quarter of fiscal year 2010, all Palo Seco generating units and the control room had returned to service.

The table on the following page shows annualized equivalent availability and the equivalent forced outage rate (an indication of the average percentage of total dependable generating capacity which is unavailable throughout the year due to forced outages or partial generating capacity outages) for fiscal years 2007 through 2011.

Electric Generation Equivalent Availability and Reliability

	2007[3]	2008[3]	2009[3]	2010	2011
Equivalent availability[1]................................	84%	80%	76%	78%	78.9%
Equivalent forced outage rate[2].....................	10%	15%	16%	12%	15.8%

[1] Cogenerator data is included.
[2] Cogenerator data is not included.
[3] Variations over previous years was due primarily to Palo Seco steam plant outage.

For planning purposes, the Authority determines adequacy of capacity using probabilistic analytic methods widely used throughout the electric utility industry. The use of these methods takes into account the unique operational aspects of the Authority.

By more effectively utilizing scheduled outages, and by implementing major design modifications, the Authority has reduced the need for extended maintenance downtime and increased the overall reliability of all of its generating facilities. The additional reserve capacity represented by the two co-generation facilities gives the Authority more flexibility in scheduling maintenance periods on its own generation facilities and favorably affects the System's equivalent availability. Total production plant availability, however, decreased consistently from 84% in fiscal year 2006 to 76% in fiscal year 2009 due primarily to the Palo Seco steam plant outage. For fiscal year 2010, total production plant availability increased to 78% and further increased to 84% for fiscal year 2011. As the Palo Seco steam plant returned to full generating capacity, the Authority has removed other generating units from service for maintenance that the Authority was not able to perform during the time the Palo Seco steam plant was out of service. The Authority calculates that each percentage point increase of System availability is equivalent to adding approximately 60 MW of available capacity to the System.

Projected Load Growth

Projections of future load growth are a key component in the Authority's financial and capacity planning. As part of its planning process, the Authority receives information from three sources relating to economic activity: Advantage Business Consulting, Inter-American University, and the Commonwealth Planning Board. The Inter-American University uses a macroeconomic model developed in conjunction with Global Insight, a nationally recognized econometrics forecasting firm. The Commonwealth Planning Board also uses data provided by Government Development Bank. The Authority's forecasts of electric energy sales and income are based in part on the correlations between the consumption of electricity and various economic and financial activities in the Commonwealth as represented in the above-mentioned models. The Authority continuously monitors actual performance relative to its forecasts and prepares new forecasts at least once a year.

The Authority incorporates the highest of the three forecasts (or the higher of two forecasts when the third is not available) as its base case for planning the additional generating capacity required by the System. Recognizing the inherent uncertainty of forecasting growth, the Authority ordinarily uses the lowest of the three forecasts (or the lower of two forecasts when the third is not available) in preparing its base case revenue forecast.

The Consulting Engineers have reviewed the Authority's projections of future load growth and estimates of peak load and have found them to provide a reasonable basis for planning purposes. See Appendix III—*Letter of the Consulting Engineers*.

The Authority's Capacity Expansion Plan

The Authority periodically updates its capacity expansion plan as part of its efforts to ensure its ability to meet expected long term electric load growth, to provide reliable, cost-effective electric service to its clients, and to reduce its dependence on fuel oil. Based on the Authority's current projections of peak load and the continued level of production plant equivalent availabilities of its generating units, the Authority and the Consulting Engineers believe that reliable service will continue to be provided to the Authority's clients through fiscal year 2016. See *Plans for Fuel Diversification – Purchase of Renewable Energy Power*.

The following table summarizes the Authority's projected peak load, dependable capacity, reserve margin and dependable reserve margin through fiscal year 2016 under the peak load projections shown below. Projections of future peak load (for capacity planning purposes) from fiscal year 2012 to fiscal year 2016 prepared by the Authority show an average annual increase of less than 1%.

Fiscal Years Ending June 30	Peak Load	Dependable Capacity	Reserve Margin	Dependable Reserve Margin (%)
		(in MW, except percentages)		
2012	3,365	5,839	2,474	74
2013	3,381	5,839	2,458	73
2014	3,410	5,839	2,429	71
2015	3,454	5,839	2,385	69
2016	3,497	5,839	2,342	67

The Consulting Engineers have examined the Authority's proposed long-term capacity expansion plan (and the methodologies and assumptions upon which it is based) and have found its development to be reasonable and generally consistent with utility industry practice and appropriate for the Authority. See Appendix III—*Letter of the Consulting Engineers*.

The Authority's recent load growth projections show that the Authority's current capacity is sufficient to meet short- to medium-term load growth demands. As a result, the Authority's capital improvement program in connection with its generating facilities is concentrated on maintaining its generating units and converting existing oil-fired generation units to dual fuel units that can burn oil and natural gas, as described below.

Plans for Fuel Diversification

Conversion of Generating Facilities to Dual Fuel

In order to reduce the Authority's dependency on fuel oil and the cost of electricity, and to comply with the MATS, the Authority is pursuing a fuel diversification strategy. The principal component of this strategy is the conversion of most of the Authority's existing oil-fired generating units to dual fuel units that can burn either oil or natural gas and the development of the necessary natural gas transportation and delivery infrastructure.

The Authority has already completed the conversion of the main generating units at the Costa Sur power plant to dual fuel, representing approximately 820 MW of generating capacity, or 14% of the Authority's total dependable generating capacity. The Authority is able to receive natural gas at Costa Sur through an existing pipeline from the EcoEléctrica LNG terminal and pursuant to a Tolling Services Agreement with Gas Natural Electricidad SDG, S.A. ("Gas Natural") whereby Gas Natural makes available to the Authority, subject to the payment of certain fees and costs, tolling services at the EcoEléctrica LNG terminal, including the berthing of LNG vessel, the unloading, receipt and storage of LNG for the Authority's account, the regasifying of LNG and the transportation of the regasified LNG. The term of the Tolling Services Agreement expires on August 1, 2020. The Authority has already conducted testing of the Costa Sur units with natural gas. The Authority is in the process of completing other necessary improvements in order to burn 100% natural gas at these units. The Authority expects to commence burning natural gas at Costa Sur in April 2012 and that the full 820 MW of capacity will be fueled with natural gas by April 2013.

The Authority's capital improvement program for fiscal years 2012 through 2016 includes the conversion to dual fuel of the main generating units at most of the other generation facilities of the Authority, representing approximately 2,420 MW of generating capacity, at an estimated cost of approximately $119.3 million. In order for the Authority to be able to burn natural gas at these other facilities, however, the Authority has to develop the associated natural gas delivery infrastructure. To this end, the Authority has been procuring the permits for Vía Verde, an approximately 93 miles long underground natural gas pipeline system that would transport natural gas from the EcoEléctrica LNG

terminal in the south to the San Juan, Palo Seco and Arecibo (Cambalache) generating plants in the north. The generating units projected to be converted to dual fuel at these generation facilities would represent an aggregate of 1,520 MW of dependable generating capacity that would be fueled with natural gas. The Authority's preliminary estimate of the cost of the Vía Verde project is approximately $450 million, of which $55 million has already been spent. The Authority has received several of the Puerto Rico permits required for construction. The only remaining permit required to be able to commence construction is the permit from the U.S. Army Corps of Engineers. Several environmental groups have expressed opposition to the project; however, the Authority expects that it will be able to obtain the remaining permit. On March 21, 2012, the Puerto Rico Supreme Court dismissed several consolidated judicial actions against Vía Verde that primarily challenged the EQB's approval of the final environmental impact statement for the project. If permits and the required project financing are obtained, the Authority expects to complete construction of this project in approximately 14 to 16 months following the receipt of permits and financing.

The Authority's capital improvement program for fiscal years 2012 through 2016 also includes the conversion to natural gas of two of Aguirre's generating units representing 900 MW of capacity, which in addition to 592 MW of capacity that has already been converted to dual fuel at Aguirre, would represent 1,492 MW of dual fuel capacity. In order to deliver natural gas to the Aguirre power plant, which is the largest of the Authority's generating plants, the Authority engaged a leading company in the development of LNG storage and regasification infrastructure to conduct a feasibility study for the engineering, procurement, construction and operation of a floating offshore LNG regasification facility. The feasibility study was completed with a positive result. This facility will require permits from the FERC and will be subject to a full environmental review and analysis under the National Environmental Policy Act. The Authority has also engaged this company to commence the permitting process, which includes a pre-filing with FERC that has already been submitted, and is currently in negotiations with the company regarding the development of this facility. If the negotiations are satisfactorily completed and the required permits and project financing are obtained, the Authority expects that the cost of this facility will be approximately $175 million and that the construction period will be approximately 12 months.

The Authority is also considering other alternatives to bring natural gas to its main generating facilities. On February 15, 2012, the Governor of Puerto Rico adopted an Executive Order creating a multi-sectoral committee, of which the Authority is a part, to study and submit a report regarding the necessary measures to comply with the new EPA rules and the impact of not complying on the economy (in particular on the manufacturing sector), and to examine all alternatives to transport and deliver natural gas to the Authority's generating plants on the north.

For a discussion of the financing alternatives being considered with respect to these projects, see *Plans for Five-Year Capital Improvement and Financing Program* under THE SYSTEM.

Transportation of Natural Gas to Puerto Rico and Projected Savings from Natural Gas Diversification Strategy.

During the past decade, LNG has been imported to Puerto Rico for use in the EcoEléctrica cogeneration facility, which has an LNG terminal. On March 28, 2012, the Authority entered into a two-year purchase agreement for natural gas in order to provide natural gas to the Authority's Costa Sur power plant, where the Authority has already completed the conversion of the main generating units to dual fuel, and is able to receive natural gas through an existing pipeline from the EcoEléctrica LNG terminal. The LNG that is imported through the EcoEléctrica LNG terminal is currently from non-U.S. sources as the United States does not currently produce LNG in the contiguous 48 states that can be delivered outside the mainland and lacks the infrastructure and facilities required for such production.

The Authority's contracted natural gas prices for the Costa Sur plant are based on a discount to the prices of fuel oil, as is typical in international markets.

In recent years, technological advances have allowed energy companies to tap into large previously untouched reserves of natural gas that could allow the U.S. to become a major producer of LNG in the future, but this would require the development of the appropriate infrastructure. While natural gas inside the U.S. mainland is generally transported via pipeline, deliveries to markets that are not accessible via pipelines would require the construction of LNG production facilities to convert the gas into liquid form and transport it via specialized tankers to foreign or domestic overseas destinations. Several companies are planning or evaluating the construction of such liquefaction plants and related facilities in the United States. Whether the infrastructure for the production of a significant amount of LNG from the U.S. mainland will be developed ultimately will depend on market conditions in the coming years and the energy policy of the United States government.

Natural gas, unlike oil, does not trade on a unified world market. Currently, there is a significant differential in the price of natural gas in international markets versus U.S. based prices, with U.S.-based prices being significantly lower. In the future, if the Authority were able to purchase LNG from the U.S. mainland, it would have to transport it in compliance with the Jones Act. The Jones Act generally requires that the transportation of merchandise between two U.S. points (including Puerto Rico) be carried in vessels that are documented in the United States, built in the United States, and owned and operated by U.S. eligible citizens. The Jones Act contains a limited exemption (adopted in 1996) for vessels that transport LNG to Puerto Rico if the vessel (1) is a foreign built vessel that was built before October 19, 1996, or (2) was documented under U.S. flag before that date, even if the vessel was thereafter redocumented under foreign flag before being redocumented under U.S. flag. In either case, the vessels still have to be U.S. owned and U.S. manned. Although there are currently no Jones Act compliant LNG vessels (either directly or within the limited exemption) operating in U.S. coastwise trade, there are some vessels currently in operation (thirteen (13) vessels that were built in U.S. yards and up to twenty-four (24) vessels that were built in non-U.S. shipyards between January 1, 1990 and October 16, 1996) that could potentially meet the previously mentioned limited exemption and be used to transport LNG from one or more future U.S. LNG production facilities to Puerto Rico. Even if such vessels were available, however, the provisions of the Jones Act would have the effect of increasing the cost of transporting LNG from the United States to Puerto Rico, as such vessels would have a higher cost profile than a foreign-flag LNG vessel. In addition, in November 2011, the U.S. Congress passed a law creating another limited exemption from the Jones Act. The law allows three specific LNG vessels (i.e., LNG Gemini, LNG Leo, and LNG Virgo) to transport natural gas between U.S. ports. This exemption may not be useful for LNG transport to Puerto Rico, since the vessels are quite old and are planned to be used as part of a project to transport ethane from Pennsylvania to the Gulf Coast. As a result, these vessels may not be available to transport natural gas between U.S. ports and Puerto Rico.

At the request of the Government of Puerto Rico, the U.S. Government Accountability Office is currently performing a comprehensive study on the Jones Act. After this study is concluded, the Government of Puerto Rico will analyze its findings and, as part of its efforts to reduce the cost of electricity in Puerto Rico, possibly seek from the U.S. Congress a broadening of the current Jones Act exemptions to include newer and more efficient LNG vessels in order to facilitate the transportation of LNG from the U.S. There is no assurance that the current exemptions will be broadened or, if they are broadened, that the Authority would be able to contract for the purchase and transportation of LNG from the U.S. mainland at lower prices than what it would be able to obtain in international markets.

The Authority estimates that the use of natural gas instead of fuel oil in the Authority's facilities that would be supplied through the Vía Verde and Aguirre projects could result in annual fuel cost savings to the Authority of between $500 million and $1.0 billion by fiscal year 2016, depending on

market prices of fuel oil and natural gas and on the Authority's execution of the plant conversions to dual fuel units that can burn oil and natural gas. To the extent that LNG is produced in the U.S. mainland and becomes available for delivery to foreign or domestic overseas markets, the price differential with international markets persists, and the Authority is able to secure transportation of such LNG in compliance with the Jones Act, as it may be amended from time to time, the Authority believes its savings from the use of natural gas could be in the upper part of the above-mentioned range. Conversely, to the extent the Authority has to continue purchasing natural gas in international markets, it believes its projected savings may be in the lower portion of this range, unless global prices come down as a result of increased production and exports of U.S. natural gas.

Purchase of Renewable Energy Power

The other principal component of the Authority's fuel diversification strategy is the development of renewable energy generation. The Authority had, as of March 1, 2012, signed power purchase agreements with respect to 33 renewable energy projects totaling approximately 1,000 MW of capacity. These projects are for renewable energy from solar, wind, waste-to-energy and landfill gas technologies. The power purchase agreements generally have a 25 year term and provide that the Authority has to accept delivery of and purchase the net electrical output from the facility to the extent it is available (except for reasons of force majeure or certain emergencies and subject to the facility complying with certain technical requirements). The table below shows the capacity of the renewable energy projects under contract by source of energy.

	Number of Projects	Capacity
Wind	9	341.9
Solar	16	400.4
Waste-to-Energy	6	243.0
Landfill Gas	2	3.5
Total	33	988.8

These renewable energy projects are in various stages of development, most still being subject to obtaining financing and permitting. Four of the projects have already obtained private financing commitments and have commenced construction. Pursuant to these power purchase agreements, the Authority has agreed to purchase energy (not capacity) at a fixed price once a particular facility has commenced operations. These agreements are subject to terms and conditions that must be met before the Authority is required to purchase any power produced, including meeting certain technical requirements with respect to the integration of the projects to the Authority's system. All of the Authority's purchased power costs under these agreements are expected to be treated as a Current Expense under the Trust Agreement.

The power purchase agreements provide for the purchase of power at fixed prices that are currently lower that the cost of the Authority's most expensive generation capacity. Over time, however, the cost of purchasing power from these renewable energy facilities could exceed the cost of energy produced by the Authority's natural gas fired units. The cost of purchased power from these facilities would be passed on to the consumer through the fuel and purchased power adjustment charges. The Authority's projections for the five fiscal years ending June 30, 2016 assume the Authority will have approximately 650 MW of renewable energy capacity by fiscal year 2016, which, based on expected availability, would represent approximately 10% of its projected energy generation. There is no assurance that these renewable energy projects will be completed or come on line by fiscal year 2016.

Statistical Information

The following table sets forth certain statistical information regarding the System for the five fiscal years ended June 30, 2011 and the six months ended December 31, 2011 and 2010. The information below includes 507 MW of capacity provided pursuant to the EcoEléctrica contract and 454 MW of capacity provided pursuant to the AES-PR contract.

Statistical Information

	Years Ended June 30					Six Months Ended December 31	
	2007	2008	2009	2010	2011	2010	2011
Nameplate rating at end of period (in MW)	5,388	5,402	5,898	5,898	5,898	5,898	5,900
Dependable generating capacity at end of period (in MW)[1]	5,365	5,372	5,839	5,839	5,839	5,839	5,839
Peak load, 60-minute (in MW)	3,604	3,546	3,351	3,404	3,406	3,406	3,303
Reserve Margin (%)	48.9	51.5	75.1	71.5	71.4	71.4	76.8
Average load (in MW)	2,863	2,721	2,586	2,692	2,583	2,673	2,588
Load factor (%)	79.4	76.7	77.2	79.1	75.8	78.5	78.4
Energy generated, purchased and sold (in millions of kWh):							
Electric energy generated and purchased[2]	25,082	23,838	22,651	23,579	22,630	11,803	11,427
Auxiliary equipment use	(1,020)	(914)	(888)	(1,020)	(991)	(519)	(497)
Net electric energy generated and purchased	24,062	22,924	21,763	22,559	21,639	11,284	10,930
Losses and unaccounted for	(3,390)	(3,322)	(3,247)	(3,324)	(3,138)	(1,613)	(1,509)
Electric Energy Sold	20,672	19,602	18,516	19,235	18,501	9,671	9,421
Electric Energy Sales (in millions of kWh):							
Residential	7,244	6,757	6,368	7,057	6,708	3,573	3,452
Commercial[3]	8,910	8,744	8,498	8,759	8,551	4,431	4,353
Industrial	4,136	3,743	3,289	3,047	2,881	1,485	1,436
Other	382	358	361	372	361	182	180
Total	20,672	19,602	18,516	19,235	18,501	9,671	9,421
Electric Energy Revenues (in thousands):							
Residential	$1,272,389	$1,498,576	$1,374,344	$1,514,413	$1,579,445	$766,969	$935,956
Commercial[3]	1,666,358	2,015,375	1,897,022	1,959,953	2,107,448	1,001,564	1,243,532
Industrial	630,569	720,912	601,985	563,915	596,046	279,028	345,519
Other	101,650	115,652	112,830	116,134	123,216	58,236	68,780
Total	$3,670,966	$4,350,515	$3,986,181	$4,154,415	$4,406,155	$2,105,797	$2,593,787
Average revenue per kWh (in cents):							
Residential	17.57	22.18	21.58	21.46	23.55	21.47	27.11
Commercial[3]	18.70	23.05	22.32	22.38	24.65	22.60	28.57
Industrial	15.24	19.26	18.31	18.51	20.69	18.79	24.07
Other	26.60	32.28	31.21	31.19	34.10	32.01	38.19
All Classes	17.76	22.19	21.53	21.60	23.82	21.77	27.53
Average number of clients:							
Residential	1,317,454	1,314,454	1,324,752	1,335,928	1,341,291	1,340,584	1,341,419
Commercial[3]	130,295	130,011	129,492	129,208	129,537	129,618	128,995
Industrial	1,576	1,514	898	808	770	781	740
Other	3,204	3,232	3,494	3,549	3,528	3,534	3,504
Total	1,452,529	1,449,211	1,458,636	1,469,493	1,475,126	1,474,517	1,474,658
Monthly average revenue per client:							
Residential	$ 80.48	$ 95.01	$ 86.45	$ 94.47	$ 98.13	$ 95.35	$ 116.29
Commercial[3]	1,065.76	1,291.80	1,220.81	1,264.08	1,355.76	1,287.84	1,606.69
Industrial	33,342.27	39,680.32	55,863.49	58,159.55	64,507.14	59,545.03	77,819.59
Other	2,643.83	2,981.95	2,691.04	2,726.92	2,910.43	2,746.46	3,271.50
All classes	$ 210.61	$ 250.17	$ 227.73	$ 235.59	$ 248.91	$ 238.02	$ 293.15

(1) Includes generating capacity of the EcoEléctrica and AES-PR cogeneration facility.
(2) Includes power purchased from EcoEléctrica and AES-PR cogeneration facility.
(3) Includes sales to the governmental sector, including central government agencies, public corporations and municipalities.

Historical Capital Improvement and Financing Program

Capital improvements and their financing are made pursuant to a program established by the Authority and reviewed annually by the Consulting Engineers. The program for the five fiscal years ended June 30, 2011 and for the six-month periods ended December 31, 2010 and 2011 is shown in the following table. Substantially all of the capital improvements have been financed with Power Revenue Bonds and other borrowed funds.

	Fiscal Years Ended June 30 (in thousands)						Six-Months Ended December 31,	
	2007	2008	2009	2010	2011	Total	2010	2011
Capital Improvements								
Production plant	$311,038	$334,309	$246,578	$139,369	$151,043	$1,182,337	$ 70,679	$ 84,524
Transmission facilities	132,771	170,244	91,508	112,760	77,745	585,028	36,528	30,717
Distribution facilities	104,826	111,849	105,028	124,963	142,461	589,127	64,063	53,182
Other[1]	36,510	50,407	37,100	9,903	40,226	174,146	12,960	24,569
Total	$585,145	$666,809	$480,214	$386,995	$411,475	$2,530,638	$184,230	$192,992

[1] Includes general land and buildings, general equipment, preliminary surveys and investigations.

Projected Five-Year Capital Improvement and Financing Program

Following a public hearing and approval by the Consulting Engineers, the Board must adopt the Authority's capital budget on or before the first day of the ensuing fiscal year. If revisions are required, the Board may amend the capital budget at any time during the fiscal year with the approval of the Consulting Engineers.

The projected capital improvement program for the five fiscal years ending June 30, 2016 (excluding the Vía Verde pipeline and the Aguirre offshore terminal projects) totals approximately $1.72 billion. It is currently estimated that substantially all of the capital improvement program will be financed with borrowed funds. Estimated capital costs reflect, among other factors, construction contingency allowances and annual cost escalations.

The five-year capital improvement program includes $644 million for production plant. Of this amount, the Authority projects that approximately $104 million will be invested during fiscal year 2012 in its production plant for the conversion of generating units to dual fuel units, to extend their useful life and continue to increase their reliability and efficiency.

The projected capital improvement program also includes $382 million for transmission facilities and $453 million for distribution facilities. During the next five fiscal years, the Authority will dedicate a significant amount of its resources to the improvement and expansion of its transmission and distribution facilities.

The Consulting Engineers have examined the projected capital improvement program and found it to be reasonable.

The capital improvement program is subject to periodic review and adjustment because of changes in expected demand, environmental requirements, design, equipment delivery schedules, costs of labor, equipment and materials, interest rates and other factors. The following table presents a summary of the projected capital improvement program for the five fiscal years ending June 30, 2016. The Authority expects that substantially all of the five-year capital improvement program will be funded through the issuance of additional Power Revenue Bonds and other borrowed funds.

Projected Capital Improvement Program
(in thousands)

	Fiscal Years Ending June 30					
	2012	2013	2014	2015	2016	Total
Capital Improvements						
Production plant	$104,340	$121,200	$151,145	$150,748	$116,875	$ 644,308
Transmission facilities	76,110	57,100	82,084	82,463	83,797	381,554
Distribution facilities	87,205	82,955	105,629	94,089	83,448	453,326
Other[1]	58,845	38,745	53,752	45,695	42,680	239,717
Total	$326,500	$300,000	$392,610	$372,995	$326,800	$1,718,905

[1] Includes general land and buildings, general equipment, preliminary surveys and investigations.

The Authority's capital improvement program through fiscal year 2016 does not include the estimated costs of Vía Verde and the offshore natural gas terminal at the Aguirre power plant, the two principal projects required in order to deliver natural gas to most of the Authority's power plants. The Authority estimates that the construction and development costs of the Vía Verde natural gas pipeline will be approximately $450 million, of which approximately $55 million has already been spent. The Authority preliminarily estimates that the construction costs of the Aguirre offshore natural gas terminal will be approximately $175 million.

The Authority, together with Government Development Bank, is evaluating various financing structures for these projects. Some of the alternatives being considered include financing these projects on a project finance, off-balance sheet basis or through fuel purchase agreements with third parties for the delivery of natural gas. Under these financing methods, the Authority would pay the capital costs of the projects through service agreements with third parties to construct and/or operate the natural gas facilities. Under these financing alternatives, payments made by the Authority for services related to the natural gas facilities or for the acquisition of natural gas from third parties would constitute a Current Expense under the Trust Agreement and, thus, would be paid prior to debt service payments on the Power Revenue Bonds. In order for payments of services related to the natural gas facilities to qualify as Current Expenses under the Trust Agreement, those facilities have to be usable and in use. Additionally, in order for payments for the acquisition of natural gas to be considered a Current Expense, such fuel must actually be ordered by the Authority, delivered by the third party and used by the Authority. Because natural gas is currently a substantially cheaper source of fuel than oil, and this price differential is projected to continue, the Authority expects that even after recouping the capital costs of the projects through the fuel adjustment charge or other charge, the generation of electricity with natural gas will result in net savings to the Authority's clients, which could also have a positive effect on electric energy demand and the Puerto Rico economy. At present, the Authority estimates that the use of natural gas instead of fuel oil in the Authority's facilities that would be supplied through the Vía Verde and Aguirre projects could result in annual fuel cost savings to the Authority of between $500 million and $1.0 billion by fiscal year 2016, depending on market prices of fuel oil and natural gas, the sourcing of natural gas and the Authority's execution of the plant conversions to dual fuel units that can burn oil and natural gas. For more information on the Vía Verde natural gas pipeline, the Aguirre offshore natural gas terminal, the sourcing of natural gas and the projected savings from the use of natural gas, see *Plans for Fuel Diversification – Conversion of Generating Facilities to Dual Fuel* and *– Transportation of Natural Gas to Puerto Rico and Projected Savings from Natural Gas Diversification Strategy* under THE SYSTEM.

Rates

Under the Act, the Authority has the power to determine, alter, establish and collect reasonable rates for electric service, which shall produce sufficient revenues to cover the operating costs of the Authority, the payment of the principal of and the interest on its bonds, and other contractual obligations. Public hearings are required before the setting of permanent rates, with the final approval vested solely

within the Authority. Act No. 21 of the Legislative Assembly of Puerto Rico, approved May 31, 1985 ("Act No. 21"), provides uniform procedures for public hearings and review of the actions of certain public corporations, including the Authority, in connection with changes in the rates set by such public corporations. Act No. 21 also authorizes the Legislative Assembly by resolution to review rates of certain public corporations, including the Authority.

Electric service rates consist primarily of (i) basic charges, made up of demand, client and energy related charges, (ii) fuel adjustment charges to recover the cost to the Authority of fuel oil, and (iii) purchased power charges to recover the cost to the Authority of power purchased from third party independent power producers such as the EcoEléctrica and AES-PR facilities. Consequently, revenues will reflect changes in the fuel charge and the purchased power charge caused by fluctuations in the price of fuel oil or purchased power. Basic charges currently average 5.7 cents per kilowatt-hour. The Authority has not increased basic charges since 1989. The table below presents the electric sales revenues derived from basic charges, fuel adjustment charges and purchased power charges for the five fiscal years ended June 30, 2011 and the six months ended December 31, 2010 and 2011.

Electric Sales Revenues
(in thousands)

	Fiscal Year Ended June 30,					Six Months Ended December 31	
	2007	2008	2009	2010	2011	2010[1]	2011[1]
Basic charges	$1,183,862	$1,131,535	$1,071,967	$1,120,904	$1,087,027	$ 563,858	$ 555,331
Fuel adjustment charges	1,778,198	2,473,227	2,161,604	2,255,989	2,578,869	1,169,564	1,638,710
Purchased power charges	708,906	745,753	752,610	777,522	740,259	372,375	399,746
Total	$3,670,966	$4,350,515	$3,986,181	$4,154,415	$4,406,155	$2,105,797	$2,593,787

[1] Unaudited

The fuel adjustment charges imposed in any month are based upon the average of (i) the actual average fuel oil costs for the second preceding month and (ii) the estimated average fuel oil costs for the current month. Purchased power charges are based on estimated purchased power costs for the current month. To the extent that such charges do not fully recover actual fuel or purchased power costs (or recover more than such costs), charges are adjusted in the second succeeding month.

Under the Act, certain residential clients receive a subsidy for the fuel adjustment charge. See *Subsidies and Contributions in Lieu of Taxes* below for a more detailed description of this and other subsidies. On December 1, 2011, the Authority implemented a temporary rate stabilization program to offer a reduction in rates to residential customers that do not benefit from the subsidy. This reduction, which is being reflected through a lower fuel adjustment charge, has resulted in an aggregate reduction in Revenues for the three months ended February 29, 2012 of approximately $25.7 million. The rate stabilization program is currently scheduled to end in May 2012 and is expected to result in an aggregate reduction in Revenues of approximately $70 million for the six month period during which it will be in effect. The Authority, however, is evaluating a possible extension of this program, although it does not expect that any such extension would have a material impact in Revenues because the reduction in rates expected to result from the commencement of burning natural gas at Costa Sur in April 2012 and the implementation of the new fuel procurement model would reduce or eliminate the rate reduction contemplated by the rate stabilization program.

To promote an increase in industrial development, the Authority instituted five new special rates in June 2003 that were available for new customers until July 30, 2008. These special rates offered a discount of approximately 11%. Qualifying industrial clients receive this discount on their total electric bill, while existing industrial clients that expanded their operations prior to July 30, 2008 receive this discount on the demand, energy, and adjustment charges associated with the expansion. Customers billed

at these rates receive the benefit of the reduced rate for a five year period. While these rates expired on July 30, 2008, they are available to existing users to complete the balance of their five year term. During fiscal years 2010 and 2011, these rates benefited qualifying industrial clients with savings of $9.8 million and $7.9 million, respectively.

During the first half of fiscal year 2010, the Authority approved a reduction in the load factor requirement applicable to Large Industrial Service 115 kV and Large Industrial Service 115 kV – Special rates in order to provide certain industries with additional operation flexibility without affecting overall electric utility charges. According to the approved modifications, the load factor requirement was reduced from 80% to 50%; provided, that if a customer does not achieve a load factor of 50% during a specific month, such customer would be billed for the additional kilowatt-hours required to achieve the 50% load factor requirement. The Authority implemented this reduced load factor requirement in order to take advantage of the excess generation capacity resulting from falling demand as a result of the extended economic recession affecting Puerto Rico.

The Authority, in its commitment to public safety, joined municipalities and communities in their efforts to improve public safety and facilitate the use of new communication technologies. For this reason, in July 2007, the Authority temporarily adopted the Unmetered Service for Small Loads Rate ("USSL"). This rate was approved permanently in January 2008. The USSL was designed to address the requests of various municipalities for the installation of security camera surveillance systems and wireless telecommunication equipment on the Authority's poles and structures.

Pursuant to the Trust Agreement, the Consulting Engineers have reviewed the Authority's rate schedules and believe that the Authority will receive sufficient Revenues to cover Current Expenses and to make the required deposits in the Sinking Fund, the Reserve Maintenance Fund and, if any are required, the Self-insurance Fund. See Appendix III—*Letter of the Consulting Engineers.* For a discussion of the impact of including the CILT and subsidies in Revenues and Net Revenues, see *Authority's Financial Condition – Subsidies and Contributions in Lieu of Taxes* under RISK FACTORS AND INVESTMENT CONSIDERATIONS, *Subsidies and Contributions in Lieu of Taxes* under THE SYSTEM, and *Projected Net Revenues* under NET REVENUES AND COVERAGE.

Major Clients

The public sector, which consists of the Commonwealth government, its public corporations and the municipalities (included primarily in the commercial category), accounted for approximately 15% of kWh sales and 17% of revenues from electric energy sales for fiscal year 2011. Of these, PRASA represents 4% of kWh sales and 4% of Revenues. PRASA has embarked in a plan to develop its own renewable energy projects and is evaluating the purchase from the Authority of the hydroelectric generating assets, which would reduce PRASA's consumption of energy from the Authority in the future. See *The Authority's Financial Condition – Sale of Hydroelectric Facilities* under RISK FACTORS AND INVESTMENT CONSIDERATIONS.

The ten largest industrial clients accounted for 4% of kWh sales and 3% of revenues from electric energy sales for fiscal year 2011. No single client accounted for more than 1% of electric energy sales or more than 1% of revenues from electric energy sales.

In September 1997, the Authority established a reduced rate for large industrial clients connected at an 115 kV voltage level and meeting certain criteria such as a minimum demand and a high load factor and power factor. This rate is designed to provide large clients with an incentive to buy more electricity from the Authority. As of June 30, 2011, two of the Authority's industrial clients were using such rate.

Fuel

For the fiscal year ended June 30, 2011, fuel oil expenses amounted to $2.3 billion, or 61.8% of total Current Expenses ($2.0 billion or 58.5% of total Current Expenses for the preceding fiscal year). For the five fiscal years ended June 30, 2011, fuel oil averaged 59.4% of average total Current Expenses for the same period. See *Management's Discussion and Analysis of Operating Results* under NET REVENUES AND COVERAGE.

The thermal generating units owned by the Authority, which produced approximately 66.5% of the net electric energy generated by the System in fiscal year 2011, are fueled by No. 6 fuel oil, except for the twenty-six smaller combustion-turbine units, the two Aguirre combined-cycle units, the 249 MW combustion turbine plant in Arecibo, and the new San Juan combined-cycle units, which burn No. 2 distillate fuel oil.

The Authority's fuel requirements for its generation facilities are covered by one-year contracts, which expire at various times and are usually renewable at the option of the Authority. The Authority's contracted fuel oil prices consist of a market based escalation factor plus a fixed price differential. The fixed price differential compensates for the fact that the fuel oil is delivered in the Commonwealth and not New York. It also takes into account other aspects of the delivery such as maximum cargo volume and draft restrictions. The Authority regularly explores alternatives to reduce its exposure to the volatility of fuel prices, such as entering into fixed price fuel supply contracts or derivative contracts for hedging oil prices. To date, the Authority does not have any hedges related to oil prices in effect.

As part of its strategic initiatives, the Authority, together with Government Development Bank, as fiscal agent, is evaluating the restructuring of the fuel procurement process in order to achieve efficiencies and savings that can result in a lower cost of fuel. The Authority expects that this initiative will be implemented by July 2012. See *Plans to Address the Authority's Challenges – Fuel Procurement Model* under OVERVIEW.

The Authority's customary inventory of fuel oil covers 40 days of ordinary operations, up from 25 days in the past. Although sources of fuel oil are continually changing as a result of variations in relative price, availability and quality, the Authority has never been forced to curtail service to its clients because of fuel oil shortages. The Authority's total inventory capacity for fuel oil is 4.7 million barrels. On October 23, 2009, the Authority's inventory of fuel oil decreased by 400,000 barrels due to an explosion at the Caribbean Petroleum Corp. ("CAPECO") oil storage facility, which stored this inventory on behalf of the Authority. The Authority's operations were not affected as a result of this explosion and it was immediately able to replace the lost inventory. As of December 31, 2011, the Authority had an inventory of 2.1 million barrels of fuel oil. In March 2011, Puma Energy Caribe ("Puma") acquired the oil storage facility through the bankruptcy court. Puma is currently refurbishing the site and is expected to be available for storage in January 2013.

Average fuel oil costs and related costs of production for the five fiscal years ended June 30, 2011 and the six months ended December 31, 2010 and 2011 are shown in the following table:

Fuel Costs

	Fiscal Year Ended June 30					Six Months Ended December 31	
	2007	2008	2009	2010	2011	2010	2011
Average fuel oil cost per barrel (net of handling costs)............	$ 57.55	$ 84.18	$ 76.23	$ 76.55	$ 95.91	$83.05	$117.01
Number of barrels used (in millions).................................	29.83	27.36	25.18	26.22	23.89	12.50	12.45
Fuel oil cost (in millions)	$1,717.0	$2,303.0	$1,919.8	$2,006.9	$2,291.4	$1,038.4	$1,456.6
Net kWh generated (excluding purchased power from 2007 to 2011) (in millions)...............	16,974.2	15,626.3	15,099.4	15,652.1	14,543.5	7,564.4	7,391.2
Average net kWh per barrel	569.0	571.1	599.7	597.0	608.8	605.2	593.7
Average fuel oil cost per net kWh generated (in cents)..........	10.12	14.74	12.71	12.82	15.76	13.7	19.7

With the addition of the output of the EcoEléctrica and AES-PR facilities to the Authority's System, the Authority's traditional dependence on oil-fired generation has decreased. The Authority estimates that approximately 31% of its annual energy requirements are now being provided by non-oil-fired generating facilities.

Subsidies and Contributions in Lieu of Taxes

Under the Act, the Authority is required to set aside 11% of the Authority's gross revenues from electric energy sales to fund certain government subsidy programs (those provided by laws in effect as of June 30, 2003), pay CILT to the municipalities and, if there is any remaining amount, fund the Authority's capital improvement program. In addition, the Authority is required to provide certain other subsidies consisting principally of a residential fuel subsidy, a residential rate subsidy and a subsidy for hotels, as described below.

Subsidies

Under the Act, a subsidy is provided for a portion of fuel charges to qualifying residential clients who use up to 425 kWh monthly or 850 kWh bi-monthly. Residential clients who qualify for the subsidy are billed the full applicable basic charges and fuel adjustment charges, with the applicable subsidy taking the form of a credit against the bill. The Act limits this subsidy to a maximum of $100 million per year and limits the cost of fuel oil used in calculating the amount of such subsidy to a maximum of $30 per barrel. The residential clients must pay any fuel adjustment charge resulting from a price of fuel oil in excess of $30 per barrel. As of the end of fiscal year 2011, there were approximately 214,175 clients, or 16% of the total residential classification, who qualified for this subsidy. For fiscal year 2011, the cost of the subsidy was $26 million. For fiscal years 2012 thru 2016, the annual average cost of the residential subsidy is expected to be $19 million.

Act No. 69 of August 11, 2009 provides residents of public housing units the alternative of receiving electric power at a fixed rate. According to the provisions of Act No. 69, the Authority is required to establish a fixed rate for electric power consumption for residents of public housing and provide a payment plan for all residents with past due amounts. Once the Authority has established its fixed rate, residents of public housing that are current with their payments may opt-out of this fixed rate program if their current rate is lower and the Authority may eliminate all state subsidy programs currently in effect. The Authority is also prohibited from suspending service to these residents unless they fail to

comply with their payment plan or the payment of the fixed rate. The Authority has approved a fixed rate from $30 to $50 (depending on the number of rooms) for a maximum consumption of 425 kWh. Approximately 35,000 residential clients currently take advantage of this fixed rate. The Authority revenues from clients under the fixed rate amounted to $16.6 million for fiscal year 2011.

Hotels receive a subsidy in an amount equal to 11% of their monthly billing, which has averaged approximately $6 million per year for the five fiscal years ended June 30, 2011. In order to receive this subsidy, hotels must maintain the hotel's electric service accounts on a current basis.

The Authority provides the residential fuel and hotel subsidy in the form of a credit against the recipient's electric bills and not as a reimbursement of a portion of their electric bills. As a result, the Authority never receives the amount corresponding to these subsidies.

In addition, the Authority has recently been offering certain discounts and incentives in the form of credits to certain industrial clients, as discussed under *Rates* above.

For a discussion of Bond Counsel's treatment of the accrued residential fuel and hotel subsidies (as described above) and the rural electrification and irrigation systems subsidies (as described below) for purposes of the additional bonds test and the rate covenant under the Trust Agreement, see *Rate Covenant* and *Additional Bonds* under SECURITY

Contributions In Lieu of Taxes

The CILT is intended to compensate the municipalities for foregone tax revenues. The Act provides that the Authority's obligations under the Trust Agreement have priority over the Authority's obligation to make any CILT. The amount of the CILT payable to the municipalities is the greater of the following amounts: (1) 20% of the Authority's Net Revenues (as defined in the Trust Agreement), after deducting from Net Revenues the cost of certain government subsidy programs; (2) actual electric power consumption by the municipalities; and (3) the prior five year average of the CILT paid to the municipalities. The CILT is payable only from Net Revenues available in each fiscal year. The Authority is required to pay the CILT no later than November 30 following the end of the fiscal year to which the CILT applies. The Act further provides that the Authority may, at its option, deduct any municipality's receivable that is outstanding at the end of any fiscal year from the CILT payable to such municipality. If the Authority does not have sufficient Net Revenues available in any fiscal year to pay the CILT to the municipalities, the difference is carried forward for a maximum of three years, at the end of which the Authority is required to pay the remaining balance, subject to the Authority's compliance with its obligations under the Trust Agreement.

While the Authority has the legal right to collect from the municipalities their electric energy consumption bills, historically the Authority has followed the practice of not pursuing the collection of the municipalities' bills for energy consumption and instead it offsets such bills against the CILT. At the end of each fiscal year, the Authority determines the amount of Net Revenues for that fiscal year available to cover the CILT. The amount so determined is applied against any CILT payable from prior fiscal years, beginning with any CILT that has then become immediately due and payable due to the three fiscal year limitation. Any remaining amount of Net Revenues is applied against the CILT for the current fiscal year. At the same time, the Authority reduces its municipalities' receivable by an amount equal to the aggregate amount of the CILT being reduced from its payables.

For fiscal year 2011, the total amount of the CILT due to the municipalities, based on the value of power consumed by the municipalities, was $212.5 million. Of this amount, the CILT paid to the municipalities corresponding to fiscal year 2011 was $99.1 million, which was applied by reducing the

outstanding municipal accounts receivable balances by that amount. The remaining balance of the CILT for fiscal year 2011 ($113.4 million) is being carried forward for payment over the next three years. The deferred CILT balance has grown steadily since the end of fiscal year 2007, when it was $34.3 million. During fiscal year 2011, the Authority also paid to the municipalities $49.9 million of outstanding unpaid CILT that had been carried forward for fiscal years 2008, 2009 and 2010 and $9.2 million to amortize the outstanding balance of a note issued to the municipalities as part of the settlement of a lawsuit brought by the municipalities against the Authority. These payments to the municipalities were all made by offsetting the municipalities' electric energy consumption receivables.

Act 233-2011, approved December 11, 2011, modifies the CILT formula to exclude from the municipality's electric energy consumption electric energy consumption related to municipal facilities in which for-profit businesses operate and for which the municipalities receive compensation through rent or an entrance fee. The Authority is in the process of implementing the provisions of Act 233-2011 by installing additional meters in municipal facilities to be able to determine the consumption that is no longer subject to the CILT. The Authority's preliminary estimate is that Act 233-2011 will result in additional collections of approximately $15 million in fiscal year 2013, $20 million in fiscal year 2014, $25 million in fiscal year 2015 and $30 million in fiscal year 2016. The Authority's projections for the five fiscal years ending June 30, 2016 take into consideration the provisions of Act 233-2011.

If the Authority were to pursue the collection of bills for energy consumption by the municipalities, there is no assurance that the Authority in fact would be able to collect such bills or, in some cases, collect such bills from many municipalities that are in a difficult financial position.

Rural Electrification and Irrigation Systems

The Authority provides certain technical and maintenance services for dams that supply PRASA and some irrigation users. The cost of these services is treated by the Authority as a subsidy.

The following table sets forth the amount of CILT that the Authority paid during fiscal year 2011 and expects to pay during the five fiscal years ending on June 30, 2016, and the residential fuel, hotel and irrigation system subsidies that the Authority incurred during fiscal year 2011 and expects to incur during the five fiscal years ending on June 30, 2016. The amounts appearing on this table for municipalities for fiscal years 2012 through 2016 represent the municipalities' expected electric power consumption in such fiscal years.

	Fiscal Years Ending June 30 (in thousands)					
Description	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Municipalities (CILT)	$158,194	$230,863	$221,269	$215,616	$216,326	$217,758
Hotel Subsidies	7,449	7,768	7,480	7,148	7,040	7,147
Subsidies:						
Irrigation Systems	4,517	6,449	6,578	6,710	6,844	6,981
Residential Customers	26,847	19,987	19,968	19,051	18,542	18,351
Total	$197,007	$265,067	$255,295	$248,525	$248,752	$250,237

Wheeling

Act No. 73 provides that the Authority shall identify and implement a system that permits the operation of a wheeling service mechanism by January 2, 2010. Act No. 73 also provides for the creation of a Committee of Wheeling, which Committee is responsible for the implementation of the wheeling system. The Committee of Wheeling engaged Christensen Associates Energy Consulting, LLC, based in Wisconsin, to prepare the Puerto Rico Wheeling System Implementation Plan Study that was delivered to the Authority in December 2009. This study, which included various regulatory proposals regarding the

establishment of the system and the applicable tariffs, was reviewed by the Authority and substantial changes were made.

Although the Authority did not meet the deadline established in the Economic Incentives Act, public hearings were held on June 1 and 2, 2010 to consider the Wheeling System Tariffs, Wheeling Transmission Regulation and Wheeling Interconnection Procedure. The public hearing examiner submitted a final report to the Authority's Governing Board on July 29, 2010. In the report, the examiner recommended approval of the Wheeling Transmission Regulation and Wheeling Interconnection Procedure, but rejected approval of the Wheeling System Tariffs based on lack of information to the public. He recommended further public hearings with enough time for public evaluation. Based on such recommendations, the Authority modified the Wheeling Transmission Tariff Schedules and held new public hearings on June 2 and 3, 2011. The public hearing examiner submitted his report to the Board of Directors on July 22, 2011, including various recommendations that are under evaluation by the Authority. Meanwhile, the Authority's Board of Directors further extended the temporarily approved wheeling system tariff structure. See *Changes in Commonwealth Legislation and Market Developments* under INVESTMENT CONSIDERATIONS.

DEBT

The following table sets forth the Power Revenue Bonds and notes of the Authority (i) outstanding as of December 31, 2011, and (ii) as adjusted for the issuance of the Bonds.

	Outstanding as of December 31, 2011	**As adjusted for the Issuance of the Bonds**
	(in thousands)	
Lines of Credit (operational)	$ 300,000	$ 300,000
Power Revenue Bonds	7,605,435	8,234,090
Other Loans and Debt (subordinated)[1]	120,505	43,105
Total	$8,025,940	$8,577,195

[1] Includes $4.9 million payable solely from Commonwealth appropriations.

Lines of Credit – Operational

As of December 31, 2011, the Authority had two one-year, revolving lines of credit provided by private financial institutions for the purchase of fuel oil and power and working capital expenses. These two lines of credit have a maximum aggregate amount of $385 million, of which $300 million was outstanding as of December 31, 2011. These lines of credit mature in June 2012 and July 2012. These lines of credit are senior to the Authority's Power Revenue Bonds as debt service payments are Current Expenses payable prior to the debt service payments on the Authority's Power Revenue Bonds.

In addition, on March 8, 2012, the Authority obtained an additional $50 million revolving credit facility from Government Development Bank to allow for timely payment for the purchase of fuel oil under the new fuel procurement process that began on a short-term basis for a portion of the Authority's fuel oil purchases. This line of credit, which expires in June 2012, is also senior to the Authority's Power Revenue Bonds.

Other Loans and Debt – Subordinated

As of December 31, 2011, the Authority had two term loans with private financial institutions that had an outstanding balance of approximately $29.9 million. The term loans are subordinated in payment priority to the Authority's Power Revenue Bonds and are payable from the subordinate

obligations fund established under the Trust Agreement, which is funded from the annual Revenues of the Authority remaining after all deposits to the Sinking Fund and the Reserve Maintenance Fund required by the Trust Agreement have been made.

The Authority also has available three lines of credit from Government Development Bank which are also subordinate in payment priority to the Authority's Power Revenue Bonds. One of these lines of credit is a non-revolving facility, with a maximum aggregate principal amount of $244 million, to be used by the Authority to pay debt service requirements on its outstanding Power Revenue Bonds for fiscal year 2012. As of December 31, 2011, $77.4 million was outstanding under this line of credit. This line of credit will be repaid with the proceeds of the Series 2012A Bonds. Another line of credit is a revolving line of credit in the maximum aggregate principal amount of $150 million to be used to cover certain collateral posting requirements under the Authority's basis swap, described below. As of the date of this Official Statement, no amounts were outstanding under this line of credit. The third line of credit had an outstanding balance of approximately $750,000 as of December 31, 2011. The Authority also had other debt in the amount of $12.4 million as of December 31, 2011.

Swap Agreements

As of July 1, 2008, the Authority entered into a basis swap agreement in the notional amount of $1.375 billion (the "Basis Swap Agreement") with an amortization schedule matching certain maturities of the Authority's outstanding power revenue and power revenue refunding bonds from 2027 to 2037. Under the terms of a master swap agreement, the Authority receives from Goldman Sachs Bank USA (as successor to Goldman Sachs Capital Markets, an affiliate of Goldman, Sachs & Co.) quarterly payments, commencing on October 1, 2008, equal to a floating amount applied to said notional amount at a rate equal to 62% of the 3-month London Inter-Bank Offered Rate ("LIBOR") index reset each week plus 29 basis points (hundredths of a percent) and a fixed rate payment of 0.4669% per annum (the "basis annuity"), quarterly for the term of the swap in return for quarterly payments by the Authority on such notional amount at a rate based on the Securities Industry and Financial Markets Association ("SIFMA") municipal swap index. The terms of the master swap agreement also require the Authority to post collateral (in cash or securities) in the event the fair value of the swap is negative and exceeds a threshold amount of $50 million, subject to adjustment based on changes to the Authority's credit ratings with Moody's Investors Service ("Moody's") and Standard & Poor's ("S&P"). If the Authority's current ratings were to be downgraded by one notch by both Moody's and S&P, the threshold would decrease to $30 million, and if the current ratings were downgraded by two notches by both Moody's and S&P the threshold would be zero. Recently, Goldman Sachs Capital Markets transferred the Basis Swap Agreement to its affiliate, Goldman Sachs Bank U.S.A.

This basis swap provides the Authority the cash flow benefit of the basis annuity in exchange for the Authority taking tax and other basis risks tied to the change in the relationship between LIBOR and the SIFMA municipal swap index. Pursuant to the Trust Agreement, regularly scheduled payments to the counterparty by the Authority and payments relating to the termination or other fees, expenses, indemnification or other obligations to the counterparty under the Basis Swap Agreement are subordinate to the Power Revenue Bonds, including the Bonds.

During fiscal years 2009, 2010 and 2011, the Authority received $7.9 million, $9.5 million and $9.6 million, respectively, from the counterparty to the basis swap, net of the Authority's payments to the counterparty. For the first six months of fiscal year 2012, the Authority received an additional $5.9 million from the counterparty. Since inception, the Authority has had a maximum collateral posting requirement of $84.2 million in November 2008. As of December 31, 2011, the basis swap had a negative fair value to the Authority of $974,546, which is below the collateral posting requirement threshold of $50 million. As of the date of this Official Statement, the fair value of the basis swap was

below the collateral posting threshold. The Authority has not been required to post collateral since January 2011.

In January 2012, the Authority terminated $225 million in notional amount under the Basis Swap Agreement in order to reduce its exposure. The Authority received $265,000 from the counterparty in connection with this termination. Following this termination, the notional amount of the basis swap is $1.150 billion.

In connection with the issuance of its Power Revenue Refunding Bonds, LIBOR Bonds Series UU (the "LIBOR Bonds") and Power Revenue Refunding Bonds, Muni-BMS Bonds Series UU (the "Muni-BMS Bonds"), the Authority entered into certain interest rate swap agreements (the "Interest Rate Swap Agreements"). The Interest Rate Swap Agreements have a current aggregate notional amount of $411.8 million, matching the principal amount of the associated Power Revenue Refunding Bonds, Series UU. Under the terms of the master swap agreement, the Authority receives from JPMorgan Chase Bank, N.A. and UBS AG (an affiliate of UBS Securities, Inc.) quarterly payments equal to a floating amount based on a rate equal to 67% of LIBOR reset each every third month plus a fixed basis point spread (hundredths of a percent), for the term of the swap in return for quarterly payments by the Authority equal to a fixed amount based on a fixed rate, in each case based on a notional amount equal to the principal amount of LIBOR Bonds outstanding. The Authority also receives from JPMorgan Chase Bank, N.A. quarterly payments equal to a floating amount based on a rate equal to 100% of the five-year SIFMA swap rate for the term of swap in return for quarterly payments by the Authority equal to a fixed amount based on a fixed rate, in each case based on a notional amount equal to the principal amount of Muni-BMS Bonds outstanding. As of December 31, 2011, the Interest Rate Swap Agreements had a negative fair value of approximately $100.8 million.

At the Authority's current rating levels by Moody's and S&P, the Authority is not subject to collateral posting thresholds on the Interest Rate Swap Agreements. In the event of downgrades to the Authority's credit ratings, however, the Authority could also be subject to collateral posting requirements on the Interest Rate Swap Agreements in the event the fair value of the swap is negative and exceeds a threshold amount. With respect to Interest Rate Swap Agreements with a notional amount of $252.9 million, which are insured, if the Authority's current ratings were to be downgraded by one notch by both Moody's and S&P, and the insurer's current ratings were also lowered, the threshold would be $50 million, and if the current ratings were downgraded by two notches by both Moody's and S&P, and the insurer's current ratings were also lowered, the threshold would be $30 million. Based on the fair value of these swap agreements as of December 31, 2011, the Authority would not have been required to post collateral under the $50 million threshold and would have been required to post $15.2 million of collateral under the $30 million threshold. With respect to the other Interest Rate Swap Agreements with a notional amount of $159.0 million, which are uninsured, if the Authority's current ratings were to be downgraded by one notch by both Moody's and S&P, the threshold would be $30 million, and if the current ratings were downgraded by two notches by both Moody's and S&P the threshold would be zero. If the collateral posting threshold with respect to the uninsured swap agreements had been $30 million, the Authority would have been required to post collateral of approximately $3.5 million as of December 31, 2011 and if the threshold had been zero, the Authority would have been required to post collateral of approximately $33.5 million.

For the fiscal year ended June 30, 2010, the Authority adopted Governmental Accounting Standards Board Statement No. 53 - Accounting and Financial Reporting for Derivative Instruments, which requires that the fair value of derivatives be reported in a government entity's financial statements. In order to comply, a journal entry for the amount of $109.9 million was booked to register a Swap Liability and a Deferred Outflow, resulting from the change in the fair market value of the derivative instruments.

The Authority regularly reviews its derivatives portfolio and from time to time may make changes that it determines to be in its best interest.

Principal and Interest Requirements

Principal and Interest Requirements, as used herein and as defined in the Trust Agreement, means for any fiscal year the sum of all principal of, including Amortization Requirements for, and interest on, outstanding Power Revenue Bonds which is payable on January 1 in such fiscal year and on July 1 in the following fiscal year. The following table shows the annual Principal and Interest Requirements for the outstanding Power Revenue Bonds after giving effect to the issuance of the Bonds and the refunding of the Refunded Bonds. The figures for interest and total debt service have been reduced by the interest that was capitalized through the issuance of the Series XX Bonds, the Series ZZ Bonds, the Series CCC Bonds, the Series DDD Bonds, and the Bonds in the following amounts: approximately $81.5 million due during fiscal year 2012, $67.1 million due during fiscal year 2013, $31.5 million in fiscal year 2014, and $15.8 million in fiscal year 2015. The Amortization Requirements are subject to adjustment as provided in the definition thereof. See Appendix I— *Definitions of Certain Terms and Summary of Certain Provisions of the Trust Agreement.*

Debt Service Requirements

Year Ending Jun 30	Outstanding Bonds Debt Service[(1)(2)]	The Bonds: Principal	The Bonds: Interest[(3)]	The Bonds: Total Debt Service[(3)]	Total Outstanding Bonds Debt Service[(2)(3)]
2012	$ 484,769,796	-	$ 1,533,208	$ 1,533,208	$ 486,303,003
2013	526,198,560	-	910,875	910,875	527,109,435
2014	561,856,727	-	910,875	910,875	562,767,602
2015	561,856,905	-	16,649,115	16,649,115	578,506,020
2016	540,510,293	$ 19,890,000	32,387,355	52,277,355	592,787,648
2017	563,003,310	-	31,476,480	31,476,480	594,479,790
2018	563,002,786	-	31,476,480	31,476,480	594,479,266
2019	563,363,113	-	31,476,480	31,476,480	594,839,593
2020	563,366,498	-	31,476,480	31,476,480	594,842,978
2021	563,366,495	-	31,476,480	31,476,480	594,842,975
2022	563,364,688	-	31,476,480	31,476,480	594,841,168
2023	563,367,202	-	31,476,480	31,476,480	594,843,682
2024	563,364,219	-	31,476,480	31,476,480	594,840,699
2025	563,343,049	-	31,476,480	31,476,480	594,819,529
2026	563,367,710	-	31,476,480	31,476,480	594,844,190
2027	563,366,927	-	31,476,480	31,476,480	594,843,407
2028	550,963,515	12,400,000	31,476,480	43,876,480	594,839,995
2029	341,629,220	179,570,000	30,856,480	210,426,480	552,055,700
2030	402,478,806	-	21,947,000	21,947,000	424,425,806
2031	405,563,762	-	21,947,000	21,947,000	427,510,762
2032	381,396,109	-	21,947,000	21,947,000	403,343,109
2033	268,453,161	-	21,947,000	21,947,000	290,400,161
2034	229,297,211	-	21,947,000	21,947,000	251,244,211
2035	229,064,323	-	21,947,000	21,947,000	251,011,323
2036	229,358,523	-	21,947,000	21,947,000	251,305,523
2037	321,779,686	-	21,947,000	21,947,000	343,726,686
2038	322,559,928	-	21,947,000	21,947,000	344,506,928
2039	296,841,308	-	21,947,000	21,947,000	318,788,308
2040	295,140,838	-	21,947,000	21,947,000	317,087,838
2041	-	213,725,000	21,947,000	235,672,000	235,672,000
2042	-	224,415,000	11,260,750	235,675,750	235,675,750
Total	$13,145,994,667	$650,000,000	$735,590,418	$1,385,590,418	$14,531,585,084

(1) Debt service requirement on all Power Revenue Bonds outstanding on the date hereof after giving effect to the refunding of the Refunded Bonds. Debt service for fiscal year 2012 includes interest paid in January 2012.

(2) The numbers shown are reduced by the amount of the Federal Build America Bonds subsidy with respect to the Power Revenue Bonds, Series EEE (Issuer Subsidy Build America Bonds) and the interest that was capitalized through the issuance of the Series XX Bonds, the Series ZZ Bonds, the Series CCC Bonds and the Series DDD Bonds in the amount of $77,659,178 in fiscal year 2012 and $35,661,344 in fiscal year 2013.

(3) The numbers shown are reduced by the interest that was capitalized through the issuance of the Bonds in the amount of $3,864,685 in fiscal year 2012, $31,476,480 in fiscal year 2013, $31,476,480 in fiscal year 2014, and $15,738,240 in fiscal year 2015.

NET REVENUES AND COVERAGE

The following table presents the Net Revenues of the Authority under the provisions of the Trust Agreement for the five fiscal years ended June 30, 2011 and for the six-months periods ended December 31, 2010 and 2011 and the ratio of such Net Revenues to Principal and Interest Requirements on the Power Revenue Bonds. The Authority calculates Revenues, Current Expenses and Net Revenues on the accrual basis. These calculations of Net Revenues differ in several important respects from the Authority's calculations of changes in net assets prepared in conformity with GAAP. For example, the calculations of Net Revenues do not include depreciation, interest expense on the Power Revenue Bonds, other post-employment benefits actuarial accruals, and CILT as a deduction in calculating Net Revenues. The figures for Revenues and Net Revenues in this table include the revenues attributable to the residential fuel, hotel and rural electrification and irrigation systems subsidies (see footnotes 2 and 3), which the Authority does not collect (in the case of the residential fuel and hotel subsidies, the Authority is required by law to provide a credit for such amounts in its recipients' billing), and the electric consumption charges of the municipalities, which the Authority does not collect because it is applied as an offset against the CILT (see footnote 3). The debt service coverage is shown as calculated under the Trust Agreement and as adjusted to reflect the elimination from Net Revenues of the municipalities' consumption and the hotel and residential subsidies. In delivering their approving opinion, Bond Counsel will take into consideration and will rely on the fact that, although the Authority includes the accrued residential fuel, hotel and rural electrification and irrigation subsidies in the calculation of Revenues for purposes of the additional bonds test and the rate covenant, even if these amounts were excluded from such calculations, both the additional bonds test for the Bonds and the Authority's rate covenant will be satisfied.

Historical Net Revenues and Coverage

	Fiscal Year Ended June 30					Six-Months Ended December 31,	
	2007	2008	2009	2010	2011	2010[1]	2011[1]
Average number of clients	1,452,529	1,449,211	1,458,636	1,469,493	1,475,126	1,474,517	1,474,658
Electric energy sales (in millions of kWh)	20,672	19,602	18,516	19,235	18,501	9,671	9,421
Source of Net Revenues (dollars in thousands)							
Revenues:							
Sales of electric energy:							
Residential[2]	$1,272,389	$1,498,576	$1,374,344	$1,514,413	$1,579,445	$ 766,969	$ 935,956
Commercial[3]	1,666,358	2,015,375	1,897,022	1,959,953	2,107,448	1,001,564	1,243,532
Industrial	630,569	720,912	601,985	563,915	596,046	279,028	345,518
Other	101,650	115,652	112,830	116,134	123,216	58,236	68,781
Sub-Total	$3,670,966	$4,350,515	$3,986,181	$4,154,415	$4,406,155	2,105,797	2,593,787
Revenues from Commonwealth for rural electrification	76	26	19	-	-	-	-
Other operating revenues	11,068	22,210	14,641	15,915	16,595	7,881	9,926
Other (principally interest earned)	5,275	(3,253)	6,427	(4,597)	(11,537)	(10,202)	1,779
Total Revenues	$3,687,385	$4,369,498	$4,007,268	$4,165,733	$4,411,213	2,103,476	2,605,492
Current Expenses:							
Operations:							
Fuel	1,716,965	2,303,036	1,919,789	2,006,931	2,291,386	1,038,356	1,456,628
Purchased power	624,653	661,097	671,849	693,724	660,872	332,233	356,182
Fuel Extra Expense Claimed[4]	(114,261)	(96,273)	-	-	-	-	-
Other production	56,170	57,507	62,271	62,697	67,451	34,326	35,996
Transmission and Distribution	157,569	171,585	162,334	160,796	176,369	94,030	86,392
Customer accounting and Collection	109,361	118,196	111,126	114,542	114,837	57,745	57,706
Administrative and General	212,530	220,553	222,477	178,982	173,502	89,033	90,548
Maintenance[5]	250,563	248,406	225,107	209,516	220,775	120,385	111,584
Other	1,433	3,963	2,819	1,907	-	2,093	0
Total Current Expenses	$3,014,983	$3,688,070	$3,377,772	$3,429,095	$3,705,192	$1,768,201	$2,195,036
Net Revenues[3]	$ 672,402	$ 681,428	$ 629,496	$ 736,638	$ 706,021	$ 335,275	$ 410,456
Coverage							
Principal and Interest Requirements[6]	$ 455,022	$ 419,569	$ 435,042	$ 397,579	$ 480,234	(7)	(7)
Ratio of Net Revenues to Principal and Interest Requirements, per Trust Agreement	1.48	1.62	1.45	1.85	1.47	(7)	(7)
Ratio of adjusted net revenues to Principal and Interest Requirements, net of municipalities' consumption and subsidies[8]	1.04	1.09	0.92	1.25	0.95	(7)	(7)

(1) Unaudited.
(2) Includes residential fuel subsidies of $27 million, $24.3 million, $30.6 million, $29.6 million and $26.8 million for fiscal years 2007, 2008, 2009, 2010 and 2011, respectively, and $12.8 million and $13.4 million for the six months ended December 31, 2010 and 2011, respectively. See *Subsidies and Contributions in Lieu of Taxes* under THE SYSTEM.
(3) Includes (i) electric energy consumption by municipalities of $159.8 million, $187.3 million, $187.6 million, $196.5 million and $212.5 million for fiscal years 2007, 2008, 2009, 2010 and 2011, respectively, and $100.0 million and $121.0 million for the six months ended December 31, 2010 and 2011, respectively; (ii) hotel subsidies of $5.6 million, $6.7 million, $6.5 million, $6.3 million and $7.4 million for fiscal years 2007, 2008, 2009, 2010 and 2011, respectively, and $3.6 million and $4.5 million for the six months ended December 31, 2010 and 2011, respectively; and (iii) rural electrification and irrigation systems subsidies of $5.7 million, $6.8 million, $4.9 million, $5.4 million and $4.5 million for fiscal years 2007, 2008, 2009, 2010 and 2011, respectively, and $2.2 million and $3.8 million for the six months ended December 31, 2010 and 2011, respectively. See *Subsidies and Contributions in Lieu of Taxes* under THE SYSTEM.
(4) Represents amounts claimed by the Authority under its insurance policies in connection with the Palo Seco steam plant fire.
(5) Includes, for maintenance of generating facilities, $134.5 million, $128.6 million, $117.3 million, $105.0 million and $107.7 million for fiscal years 2007, 2008, 2009, 2010 and 2011, respectively, and $58.5 million and $59.1 million for the six months ended December 31, 2010 and 2011, respectively.
(6) The Principal and Interest Requirements for fiscal years 2008, 2009, 2010 and 2011 have been reduced by the interest that was capitalized through the issuance of Power Revenue Bonds in the amounts of $21.2 million, $37.7 million, $8.4 million and $79.5 million, respectively. The Principal and Interest Requirements for fiscal year 2010 have been adjusted to reflect the restructuring of $73.9 million of the Authority's debt service requirements for such fiscal year through the issuance of Power Revenue Bonds, the proceeds of which were used to pay debt service for that fiscal year. The Principal and Interest Requirements for fiscal year 2011 have been further reduced by the amount of the Federal Build America Bonds subsidy on the Power Revenue Bonds, Series YY and Series EEE, equal to 35% of the interest payable on such Bonds.
(7) Calculated only for full fiscal year.
(8) Excludes from Net Revenues, for purposes of computing this ratio, the basic charges and fuel and purchased power adjustment charges attributable to energy consumption by the municipal governments as well as the subsidies for energy consumption charges provided by law to certain residential customers and hotels and those subsidies related to rural electrification and irrigation systems, in the amounts set forth in footnotes (2) and (3) above, which are not collected.

Although the ratio of adjusted net revenues (net of municipalities' consumption and subsidies) to Principal and Interest Requirements was below 1.00 for fiscal years 2009 and 2011, the Authority made timely payments on its Power Revenue Bonds in such fiscal years. The Authority, however, has had to obtain additional borrowings in order to meet all of its operational and financial obligations. See *The Authority's Financial Condition* under RISK FACTORS AND INVESTMENT CONSIDERATIONS.

The Authority's rate covenant requires that it will at all times fix, charge and collect reasonable rates and charges for the use of the services and facilities furnished by the System so that Revenues are sufficient to pay Current Expenses of the System and to provide an amount at least equal to 120% of the aggregate Principal and Interest Requirements for the next fiscal year on account of all bonds then Outstanding. Pursuant to the accrual method of calculating Revenues and Current Expenses under the Trust Agreement, the Authority is in compliance with the rate covenant, even if the accrued residential fuel, hotel and rural electrification and irrigation system subsidies are excluded from Revenues.

Management's Discussion and Analysis of Operating Results

The following represents the Authority's analysis of its operations for the five fiscal years ended June 30, 2011 and the six months ended December 31, 2011 and 2010. For additional analysis of the Authority's results of operations, see *Management's Discussion and Analysis* in the Authority's audited financial statements, included as Appendix II.

Six months ended December 31, 2011 compared to six months ended December 31, 2010

Net Revenues for the six months ended December 31, 2011 were $410.5 million, representing an increase of $75.2 million, or 22.4%, from the same period in the prior year. Net Revenues increased despite a 2.6% decrease in electric energy sales (in kWh), primarily as a result of higher revenues from the fuel and purchased power adjustment charges relative to the increase in the cost of fuel and purchased power due to differences between these adjustment charges, as determined by the Authority's formula, and actual costs of fuel and purchased power for the period. Revenues for the six months ended December 31, 2011 were $2.605 billion, a 23.9% increase from the same period of the prior year, mainly as a result of an increase in the revenues from the fuel adjustment charge due to the 40.3% increase in the costs incurred by the Authority for the purchase of fuel oil during the period, compared to the same period in the prior year. Current Expenses, which include fuel and purchased power, maintenance, administrative and general expenses, among others, were $2.195 billion for the period, a 24.1% increase from the same period in the prior year. The increase in Net Revenues during the six month period was also due in part to a decrease in maintenance expenses of $8.8 million, or 7.3%, and a decrease in transmission and distribution expenses of $7.6 million or 8.1%. These expenses during the comparable period of 2010 had been higher than normal due to poor weather conditions that required higher maintenance and transmission and distribution expenses. Administrative and general expenses of $90.5 million for this period were 1.7% higher than in the comparable period of 2010. The accrued revenues attributable to the municipalities' consumption and the residential fuel, irrigation system and hotel subsidies increased from $118.6 million for the six months ended December 31, 2010 to $142.7 million for the six months ended December 31, 2011, or 20.3%.

Accounts receivable from the sale of electric energy (excluding billings to municipalities) increased from $807.5 million as of December 31, 2010 to $988.9 million as of December 31, 2011. The increase in accounts receivable was mainly the result of the increase in the fuel adjustment charge due to the increase in the cost of fuel and slower payments by clients. Accounts receivable from government clients (excluding municipalities) increased from $210.3 million as of December 31, 2010 to $269.4 million as of December 31, 2011, of which 81% were considered past due (in excess of 30 days) as of December 31, 2011, compared to 79% as of December 31, 2010. Accounts receivable from general

clients increased from $597.2 million as of December 31, 2010 to $719.5 million as of December 31, 2011, of which 10% were past due as of December 31, 2011, compared to 12% as of December 31, 2010.

Fiscal year 2011 compared to fiscal year 2010

Net Revenues for fiscal year 2011 were $706.0 million, representing a decrease of $30.6 million, or 4.2%, from Net Revenues for fiscal year 2010. The decrease in Net Revenues was primarily the result of a 3.8% decrease in electric energy sales (in kWh) and increases in maintenance expenses of $11.3 million, or 5.4%, and in transmission and distribution expenses of $15.6 million, or 9.7%. Revenues were $4.4 billion, a 5.9% increase from the prior year as a result of an increase in the revenues from the fuel adjustment charge due to the 14.2% increase in the costs incurred by the Authority for the purchase of fuel oil during the period, compared to the prior year. Current Expenses, which include fuel and purchased power, maintenance, administrative and general expenses, among others, were $3.7 billion for the year, an 8.1% increase from the prior year. Fuel and purchased power expenses, the principal component of the Authority's Current Expenses, are passed on to clients through a separate fuel adjustment charge included in electric service rates. The Authority's revenues from its basic charges (which exclude the fuel adjustment charge) decreased by 3.0% from fiscal year 2010 to fiscal year 2011 as a result of the decrease in electric energy sales. Excluding fuel and purchased power expenses, Current Expenses increased from $728.4 million for fiscal year 2010 to $752.9 million for fiscal year 2011, or 3.4%, as a result of the increases in maintenance and transmission and distribution expenses mentioned above. The increase in these expenses was due in part to increases in salaries pursuant to the collective bargaining agreement with the Authority's principal union. The accrued revenues attributable to the municipalities' consumption and the residential fuel, irrigation and hotel subsidies increased from $237.8 million for fiscal year 2010 to $251.2 million for fiscal year 2011, or 5.6%. See *Subsidies and Contributions in Lieu of Taxes* under THE SYSTEM.

During fiscal year 2011, accounts receivable from the sale of electric energy (excluding billings to municipalities) increased from $932.1 million as of June 30, 2010 to $1.0 billion as of June 30, 2011. The increase in accounts receivable was mainly the result of the increase in the fuel adjustment charge, due to the increase in the cost of fuel, and slower payments by clients. Accounts receivable from government clients (excluding municipalities) increased from $274.7 million as of June 30, 2010 to $282.3 million as of June 30, 2011, of which 78% were considered past due (in excess of 30 days) as of June 30, 2011, compared to 73% as of June 30, 2010. Accounts receivable from general clients (residential, industrial and commercial) increased from $657.4 million as of June 30, 2010 to $720.1 million as of June 30, 2011, of which 8% were past due as of June 30, 2011, compared to 10% as of June 30, 2010.

Fiscal year 2010 compared to fiscal year 2009

For the fiscal year ended June 30, 2010, as compared to the fiscal year ended June 30, 2009, Net Revenues increased by $107.1 million, or 17.0%. This increase was mainly due to an increase of 3.9% in electric energy sales (kWh), which resulted in an increase of $158.5 million, or 4.0%, in Revenues. Although Current Expenses increased by $51.3 million, or 1.5%, administrative and general expenses decreased by $43.5 million, or 19.6%. Accounts receivable decreased from $1.019 billion as of June 30, 2009 to $976.4 million as of June 30, 2010. Of this total, $373.1 million were due from the Commonwealth central government and the public corporations, a decrease from $471.4 million as of June 30, 2009.

Fiscal year 2009 compared to fiscal year 2008

For the fiscal year ended June 30, 2009, as compared to the fiscal year ended June 30, 2008, Net Revenues decreased by $52 million, or 7.6%. This decrease was mainly due to a reduction of 5.5% in electric energy sales (kWh). Revenues decreased by $362 million, or 8.3%, as a result of the reduction in energy sales and a reduction in the price of fuel from $84.18 per barrel in 2008 to $76.23 per barrel in 2009. Current Expenses decreased by $310 million, or 8.4%. Fuel and purchased power expenses, the largest component of Current Expenses, were down by $372 million or 12.6%, partly because of the reduction in the price of fuel, but also because in 2008 the Authority incurred additional fuel expense resulting from the Palo Seco fire that occurred in December 2006. A portion of this extra cost ($96 million in 2008) is being claimed by the Authority from its insurers and is shown as a separate line item. Maintenance expenses also declined by $23 million or 9.4% when compared with 2008. Accounts receivable as of June 30, 2009, decreased by 3.1%, to $1.019 billion, when compared by 2008. Of this total, $471.3 million were due from the Commonwealth central government and the public corporations, an increase of 31.9% from the previous year.

Fiscal year 2008 compared to fiscal year 2007

For the fiscal year ended June 30, 2008, as compared to the fiscal year ended June 30, 2007, Net Revenues increased by $9 million, or 1.3%, despite a 5.2% decrease in electric energy sales (kWh). The increase in Net Revenues was primarily due to a 46.3% increase in the price of fuel, which resulted in an increase of $623 million, or 26.6%, in fuel and purchased power expense, an increase of $673 million, or 22.3%, in Current Expenses, and an increase of $682 million, or 18.5%, in Revenues. Administrative and general expenses, another component of Current Expenses, increased by $8 million, or 3.8%. The Authority incurred additional fuel expense in both 2007 and 2008 as a result of the Palo Seco fire that occurred in December 2006. A portion of this extra cost ($114 million in 2007 and $96 million in 2008) is being claimed by the Authority from its insurers and is shown as a separate line item. Accounts receivable of the Authority increased from $835.9 million on June 30, 2007 to $1.061 billion on June 30, 2008. Accounts receivable due from the Commonwealth central government and the public corporations increased from $316.6 million on June 30, 2007 to $357.3 million on June 30, 2008.

Historical Disposition of Net Revenues
(in thousands)

	Fiscal Year Ended June 30					Six-Months Ended December 31,	
	2007	2008	2009	2010	2011	2010	2011
Disposition of Net Revenues							
Sinking Fund:							
Interest	$257,457	$255,593	$261,486	$246,072	$304,778	$152,706	$149,869
Principal	197,565	164,492	173,040	151,507	175,455	87,727	92,803
Reserve Account	-	-	(29,523)	-	-	-	-
Reserve Maintenance Fund	-	-	-	-	-	-	-
Self-insurance Fund	-	(20,438)	10,000	10,000	10,000	-	-
Capital Improvement Fund	10,212	11,400	4,695	63,405	17,231	4,359	35,951
Interest on Notes	38,922	44,291	28,434	33,985	1,550	632	730
Contributions in lieu of taxes and other uses[(1)]	168,246	226,090	181,364	231,669	197,007	89,851	131,103
Net Revenues	$672,402	$681,428	$629,496	$736,638	$706,021	$335,275	$410,456

[(1)] Includes the following amounts attributable to the residential fuel subsidy and the subsidy granted to the hotel industry: $32.6 million, $31.0 million, $37.1 million, $35.9 million and $34.2 million for fiscal years ended June 30, 2007, 2008, 2009, 2010 and 2011, respectively. See *Subsidies and Contributions in Lieu of Taxes* under THE SYSTEM.

Since Net Revenues include amounts billed to the municipalities and other subsidies that are not collected, as discussed previously, in some years, the Authority may not have had sufficient cash available to make the deposits and payments shown above as being made prior to the application of "Contributions in lieu of taxes and other uses." In those years, the Authority made some of the deposits and payments from additional borrowings.

Projected Net Revenues

The main assumptions used by the Authority in preparing the estimates of Net Revenues set forth below are the following:

Revenues - Projected Revenues from sales of electric energy are based upon economic growth projections for the Commonwealth. The Revenue projections assume that sales in kWh will decline by 3.03% and 1.11% for fiscal years 2012 and 2013, respectively, and increase by 0.32%, 1.07%, and 1.52% for fiscal years 2014, 2015 and 2016, respectively.

Current Expenses - Projected Current Expenses assume reductions in operating expenses (excluding fuel, purchased power and maintenance expenses) as a result of expense reduction measures the Authority expects to undertake, of 4.3%, 4.0%, 3.0%, 2.0% and 1.0% for fiscal years 2012, 2013, 2014, 2015 and 2016, in each case compared to the preceding fiscal year.

Fuel - Projected fuel oil prices are based upon an analysis prepared by the Authority, which takes into consideration the Annual Energy Outlook issued by the United States Department of Energy and the Authority's historical fuel data. The Authority passes through the cost of fuel oil to its consumers. The following table sets forth projected average per barrel fuel prices:

Projected Fuel Oil Prices

Fiscal Year Ending June 30	Average Price Per Barrel[1]
2012	$117.09
2013	110.93
2014	105.00
2015	105.89
2016	102.63

[1] This is a blended price of No. 2 and No. 6 fuel oil prices. The prices exclude handling charges.

The following table presents the Authority's estimates of Net Revenues for the five fiscal years ending June 30, 2016, in accordance with the provisions of the Trust Agreement, and the ratio of Net Revenues to Principal and Interest Requirements for Power Revenue Bonds. The figures for Revenues and Net Revenues in this table include the revenues attributable to the residential fuel, hotel and rural electrification and irrigation systems subsidies (see footnotes 2 and 3), which the Authority does not collect (in the case of the residential fuel and hotel subsidies, the Authority is required by law to provide a credit for such amounts in its recipients' billing), and the electric consumption charges of the municipalities, which the Authority is legally authorized to collect but does not because it follows the practice of applying them as an offset against the CILT obligation (see footnote 2). See *Authority's Financial Condition - Subsidies and Contributions in Lieu of Taxes* under INVESTMENT CONSIDERATIONS and *Subsidies and Contributions in Lieu of Taxes* under THE SYSTEM. As discussed under THE SYSTEM – *Additional Bonds*, in delivering their approving opinion, Bond Counsel will take into consideration and will rely on the fact that, although the Authority includes the hotel, residential and irrigation subsidies in the calculation of Revenues, even if these amounts were excluded from such calculation, the additional bonds test described above will be satisfied.

The Principal and Interest Requirements in this table for fiscal year 2012 are reduced by the $158.3 million deposited with the Trustee from a Government Development Bank line of credit for the

payment of principal and interest on the Power Revenue Bonds for fiscal year 2012, which is being refinanced with the proceeds of the Series 2012A Bonds. The Principal and Interest Requirements in this table for fiscal years 2012 through 2016 are further reduced by (i) the interest that was capitalized from the issuance of the Authority's Series XX Bonds, Series ZZ Bonds, Series CCC Bonds, Series DDD Bonds, and the Bonds of approximately $81.5 million due during fiscal year 2012, $67.1 million due during fiscal year 2013, $31.5 million in fiscal year 2014, and $15.8 million in fiscal year 2015, and (ii) the interest that is expected to be capitalized with the issuance of additional Power Revenue Bonds during this five-year period. The aggregate reductions to Principal and Interest Requirements for each fiscal year during the projection period attributable to capitalized interest are $81.5 million for fiscal year 2012, $67.1 million for fiscal year 2013, $61.2 million for fiscal year 2014, $73.6 million for fiscal year 2015 and $80.9 million for fiscal year 2016.

The projections set forth in the following table assume that the Authority will commence to burn natural gas at the Costa Sur power plant in April 2012 and that the full 820 MW of dual fuel capacity at Costa Sur will be fueled with natural gas by April 2013. The projections also assume that, under power purchase agreements, the Authority will have renewable energy capacity of approximately 285 MW by fiscal year 2013, 383 MW by fiscal year 2014, 565 MW by fiscal year 2015 and 650 MW by fiscal year 2016. See *Plans for Fuel Diversification* under THE SYSTEM.

The projections do not take into consideration the costs of financing the Vía Verde and Aguirre offshore terminal projects and the estimated annual fuel cost savings expected to be derived from the use of natural gas at the generating units to be supplied by these two projects, the impact of such projects on Net Revenues, or the resulting impact on the ratio of Net Revenues to Principal and Interest Requirements. The cost of these projects is not included in the Authority's current capital improvement program for fiscal years 2012-2016. To the extent that the costs of financing the Vía Verde and Aguirre offshore terminal projects are not offset by higher Net Revenues, the actual coverage ratio would be lower than that set forth below. For a discussion of the financing alternatives being considered with respect to these projects, see *Projected Five-Year Capital Improvement and Financing Program* under THE SYSTEM.

Projected Net Revenues and Coverage

	Fiscal Year Ending June 30				
	2012	**2013**	**2014**	**2015**	**2016**
Average number of clients	1,473,376	1,474,507	1,475,683	1,476,905	1,477,984
Electric energy sales (in millions of kWh)	17,940.2	17,741.1	17,797.3	17,987.5	18,261.6
Authority generation (gross)(in millions of kWh)	15,244.7	14,487.7	14,000.4	13,526.1	13,474.4
Purchased generation (gross)(in GWHR)	6,739	7,214	7,770	8,477	8,864
Sources of Net Revenues					
Revenues:					
Sales of electric energy:					
Residential[1]	$1,780,767	$1,708,419	$1,674,044	$1,697,531	$1,722,273
Commercial[2]	2,387,897	2,274,501	2,205,299	2,212,184	2,226,008
Industrial	659,269	615,562	596,181	604,335	617,575
Other	137,751	133,466	130,512	130,319	130,329
Theft Recovery[3]	25,000	30,000	30,000	30,000	30,000
Rate Stabilization[4]	(70,000)	-	-	-	-
Sub-Total	4,920,684	4,761,948	4,636,036	4,674,369	4,726,185
Revenues from Commonwealth for Rural Electrification	-	-	-	-	-
Other (principally interests earned)	5,058	5,058	5,058	5,058	5,058
Total Revenues	$4,925,742	$4,767,006	$4,641,094	$4,679,427	$4,731,243
Current Expenses:					
Operations:					
Fuel	$2,802,337	$2,472,915	$2,281,957	$2,187,275	$2,136,881
Purchased Power	672,026	802,042	879,509	999,854	1,083,858
Production	60,751	54,580	50,136	47,263	45,855
Transmission and Distribution	168,569	161,384	156,212	152,867	151,227
Maintenance	220,775	220,775	220,775	220,775	220,775
Client accounting and collection	112,837	110,995	109,668	108,811	108,390
Administration and general	157,708	144,080	134,269	127,924	124,814
Total Current Expenses	$4,195,003	$3,966,771	$3,832,526	$3,844,768	$3,871,801
Net Revenues[1][2]	$ 730,739	$ 800,235	$ 808,568	$ 834,659	$ 859,442
Coverage					
Principal and Interest Requirements[5]	328,021	527,109	562,768	578,506	592,788
Ratio of Net Revenues to Principal and Interest Requirements, per Trust Agreement	2.23	1.52	1.44	1.44	1.45
Ratio of adjusted net revenues to Principal and Interest Requirements, net of municipalities' consumption and subsidies[6]	1.42	1.06	1.03	1.06	1.08

(1) Includes residential fuel subsidies of approximately $20 million, $20 million, $19.1 million, $18.5 million and $18.4 million for fiscal years 2012, 2013, 2014, 2015 and 2016, respectively. See *Subsidies and Contributions in Lieu of Taxes* and *Additional Bonds* under THE SYSTEM.

(2) Includes (i) electric energy consumption by municipalities of approximately $230.7 million, $221.3 million, $215.6 million, $216.3 million and $217.8 million for fiscal years 2012, 2013, 2014, 2015 and 2016, respectively; (ii) hotel subsidies of approximately $7.8 million, $7.5 million, $7.1 million, $7.0 million and $7.1 million for fiscal years 2012, 2013, 2014, 2015 and 2016, respectively; and (iii) rural electrification and irrigation systems subsidies of $6.4 million, $6.6 million, $6.7 million, $6.8 million and $7.0 million for fiscal years 2012, 2013, 2014, 2015 and 2016, respectively. See *Subsidies and Contributions in Lieu of Taxes* and *Additional Bonds* under THE SYSTEM.

(3) Projections based on the Authority's theft recovery initiatives. See *Transmission and Distribution Facilities – Operations* under THE SYSTEM.

(4) Represents the estimated reduction in Revenues from the temporary rate stabilization program to non-subsidized residential customers. See *Rates* under THE SYSTEM.

(5) Includes debt service requirements for (i) the outstanding Power Revenue Bonds, (ii) the Bonds, and (iii) Power Revenue Bonds expected to be issued in each of fiscal years 2013-2016 to fund the Authority's capital improvement program (which does not include the Via Verde pipeline and the Aguirre offshore terminal projects) at an assumed interest rate of 6% with interest capitalized for approximately three years. See *Projected Five-Year Capital Improvement and Financing Program* under THE SYSTEM. The Principal and Interest Requirements in this table for fiscal year 2012 are reduced by the $158.3 million deposited with the Trustee from a Government Development Bank line of credit for the payment of principal and interest on the Power Revenue Bonds for fiscal year 2012, which is being refinanced with the proceeds of the Series 2012A Bonds. The Principal and Interest Requirements in this table for fiscal years 2012 and 2013 are further reduced by the interest that was capitalized through the Authority's issuance of its Series XX Bonds, its Series ZZ Bonds, the Series CCC Bonds, the Series DDD Bonds and the Bonds in the following amounts: approximately $81.5 million due during fiscal year 2012, $67.1 million due during fiscal year 2013, $31.5 million in fiscal year 2014, and $15.8 million in fiscal year 2015. Actual Principal and Interest Requirements will vary based on the actual principal and interest on the future Power Revenue Bonds and Power Revenue Refunding Bonds issued and no assurance can be given that the assumed reductions in Principal and Interest Requirements or any other level of reductions will actually be achieved.

(6) Excludes from Net Revenues, for purposes of computing this ratio, the basic charges and fuel and purchased power adjustment charges attributable to energy consumption by the municipal governments (net of projected recoveries as a result of Act 233-2011 of $15 million in fiscal year 2013, $20 million in fiscal year 2014, $25 million in fiscal year 2015, and $30 million in fiscal year 2016) as well as the subsidies for energy consumption charges provided by law to certain residential customers and hotels, and other subsidies related to the irrigation system, in the amounts set forth in footnotes (1) and (2) above, which are not collected.

The Consulting Engineers had initially reviewed a different set of projections than those set forth above in their Thirty-Eighth Annual Report to the Trustee required by the Trust Agreement. The prior projections showed a lower level of Net Revenues, when compared to the projections set forth above, in each of fiscal years 2013, 2014, 2015 and 2016 of $33 million, $54 million, $67 million and $74 million, respectively. These prior projections showed a constant level of operating expenses (excluding fuel and

purchased power) and did not take into consideration the further expense reduction initiatives that the Authority expects to undertake. The Authority revised its prior projections to consider the following factors: (i) further reductions in operating expenses in those fiscal years of \$29 million, \$50 million, \$63 million and \$70 million, respectively, expected to be achieved as a result of the implementation of further expense reduction initiatives, and (ii) additional revenues of \$5 million per fiscal year from theft reduction initiatives. The projections set forth above show an aggregate reduction in operating expenses (excluding fuel, purchased power and maintenance) by fiscal year 2016 of \$102 million, or 19%, compared to the level of these operating expenses in fiscal year 2011. The expense reduction initiatives include, among others, the restructuring of supply chain processes, customer service and collection processes and general and administrative processes, improvement of inventory management, and headcount reductions through attrition. There can be no assurance, however, that the Authority will in fact be able to achieve the expected reductions in every year.

The Consulting Engineers have reviewed and analyzed the revised projections of the Authority shown above and will amend their Thirty-Eighth Annual Report to reflect these projections. Based on the assumptions set forth in their letter, the Consulting Engineers have concluded that (i) the methodology used by the Authority in preparing its revenue and capacity projections generally follows accepted utility practice and is appropriate for the Authority, (ii) the Authority's estimates of future growth form a reasonable basis for its projected operating results, and (iii) the Authority's rates should generate sufficient revenues to pay its Current Expenses and debt service and to meet the Trust Agreement obligations for deposits into certain funds from current operating revenues. See Appendix III—*Letter of Consulting Engineers.*

Although the Authority and the Consulting Engineers believe that the assumptions upon which the estimates of Net Revenues are based are reasonable, actual results may differ from the estimates as circumstances change. The Authority's financial projections involve many assumptions, some of which are beyond the control of the Authority, such as the cost of fuel oil and its impact on the level of demand for electricity. In the past, the Authority's projections of Net Revenues have at times materially differed from what the Authority has been able to achieve.

If the Authority is unable to obtain the level of Net Revenues it has projected, it will not be able to meet its Principal and Interest Requirements unless it borrows funds to meet its debt service or implements measures to increase Revenues and/or reduce its Current Expenses. See the discussion in *The Authority's ability to meet its projections of Net Revenues* under RISK FACTORS AND INVESTMENT CONSIDERATIONS for a discussion of factors that can affect the Authority's ability to achieve its projected Net Revenues.

The Authority's projections were not intended to comply with the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of financial projections. The projections have been prepared on the basis of Net Revenues as defined in the Trust Agreement, which differs in several important respects from the Authority's net income prepared in conformity with GAAP in that they do not include, for example, depreciation, other post-employment benefits actuarial accrual and the CILT as a current expense and do not reflect interest expense on Power Revenue Bonds as a deduction from Net Revenues.

The following table presents the projected disposition of Net Revenues, in the order of priority of payment, for the five fiscal years ending June 30, 2016, in accordance with the provisions of the Trust Agreement.

Projected Disposition of Net Revenues
(in thousands)

	Fiscal Year Ended June 30				
	2012	**2013**	**2014**	**2015**	**2016**
Disposition of Net Revenues					
Sinking Fund:					
Interest	$172,294	$332,189	$358,463	$364,096	$347,408
Principal	155,728	194,920	204,305	214,410	245,380
Reserve Account	-	-	-	-	-
Reserve Maintenance Fund	-	-	-	-	-
Self-insurance Fund	5,000	-	-	-	-
Capital Improvement Fund	131,181	26,459	4,720	21,901	38,417
Interest on Notes	1,469	6,372	12,555	10,500	8,000
Contributions in lieu of taxes and other uses(1)	265,067	240,295	228,525	223,752	220,237
Net Revenues	$730,739	$800,235	$808,568	$834,659	$859,442

(1) Includes the following amounts attributable to the residential fuel subsidy and the subsidy granted to the hotel industry: $27.8 million, $27.5 million, $26.2 million, $25.5 million and $25.5 million for fiscal years ended June 30, 2012, 2013, 2014, 2015 and 2016, respectively. See *Subsidies and Contributions in Lieu of Taxes* under THE SYSTEM.

Since Net Revenues include amounts billed to the municipalities and other subsidies that are not collected, as discussed previously, in some years, the Authority may not have sufficient cash available to make the deposits and payments shown above as being made prior to the application of "Contributions in lieu of taxes and other uses." In those years, the Authority may have to make some of the deposits and payments from additional borrowings.

ENVIRONMENTAL MATTERS

The Authority's Environmental Protection and Quality Assurance Division is responsible for ensuring the Authority's compliance with all applicable federal and Commonwealth environmental laws and regulations. The Division is in charge of developing and implementing a comprehensive program to improve the Authority's performance in all applicable environmental media, taking into account new regulatory requirements as well as alleged instances of noncompliance cited by the EPA and any other environmental agencies.

Environmental Litigation and Administrative Proceedings

Consent Decree

1992, the EPA conducted a multimedia inspection of the Authority's facilities and identified several alleged instances of non-compliance related to the Authority's air, water and oil spill prevention control and countermeasures compliance programs, among other things. As a result, the EPA filed a complaint against the Authority on October 27, 1993 seeking injunctive relief and the imposition of penalties for alleged violations of the CAA, the CWA, the Emergency Planning and Community Right-to-Know Act ("EPCRA"), the Comprehensive Response, Compensation and Liability Act ("CERCLA") and the Resource Conservation and Recovery Act ("RCRA"). To settle the complaint, the Authority and the EPA entered into a consent decree (the "Consent Decree") approved by the United States federal court in 1999.

The Consent Decree covered alleged violations with respect to the Authority's electric power generating plants in Aguirre, Palo Seco, San Juan and the South Coast and the Authority's main transmission center in Monacillos, San Juan. Under the terms and conditions of the Consent Decree, the Authority was required to: (i) implement measures to ensure that the operation of its generating units complies with the opacity standards applicable to air emissions under the EQB's Regulation for the Control of Atmospheric Pollution ("RCAP"), among other things, including the refurbishment of generating units and the implementation of operation and maintenance programs (termed, "Air Compliance Programs"); (ii) achieve and maintain compliance with the CWA and NPDES permit requirements by implementing certain upgrades and modifications of the discharges of each power plant; (iii) operate its facilities in compliance with Oil Spill Prevention and Spill Prevention Control and Countermeasure ("SPCC") requirements of the CWA, including the preparation and implementation of SPCC plans for all of the power plants and the transmission center and the implementation of a construction and maintenance program to modify these facilities to achieve compliance; (iv) achieve compliance with EPCRA requirements by filing hazardous chemical reporting forms that were not filed when due in the past (known as "Tier I/Tier II" forms) and conduct any current and future filings; (v) achieve compliance with CERCLA and EPCRA with respect to potential releases from its facilities by implementing an in-house hazardous material spill training for employees and contractors; and (vi) achieve compliance with RCRA's underground storage tank requirements by ensuring that all underground storage tanks at its facilities were closed or removed in compliance with these requirements.

As part of the Air Compliance Program, the Authority is required to combust fuel with low sulfur content, as per the specifications in the Consent Decree, in order to achieve compliance with air emission opacity standards. Furthermore, under the Consent Decree, the Authority was required to pay a civil penalty of $1.5 million, and implement additional compliance projects amounting to $4.5 million, which include $1 million to hire an independent party to review the Authority's implementation of the terms of the Consent Decree and inform the public about it (the "Environmental Review Contractor"), $100,000 for a fire department hazmat training, and $3.4 million to implement an environmental restoration and protection project. The University of Puerto Rico's Graduate School of Public Health was subsequently hired as the Environmental Review Contractor. The Consent Decree can be terminated or modified if the Authority shows compliance for three years.

To settle a dispute between the Authority and EPA regarding the application of a method for performing air opacity readings and alleged violations of the opacity standards by the Authority, in 2004 the Authority and the EPA entered into a Consent Decree modifying the Consent Decree, which was approved by the United States federal court. Under this agreement, the Authority was required to reduce, in two steps, the sulfur content in the No. 6 fuel oil used in certain generating units of its South Coast and Aguirre power plants (to 0.75% or less by March 1, 2005 and to 0.5% or less by March 1, 2007), and use No. 6 fuel oil with sulfur content of not more than 0.5% through July 18, 2009 at its Palo Seco and San Juan power plants. The Authority was also given the option of installing pollution controls in lieu of using fuel with 0.5% sulfur or less, but only if the equipment reduces sulfur dioxide emissions as much as they would have been reduced using the cleaner fuel. Additionally, the Authority was required to conduct a nitrogen oxide emissions reduction program and modify the optimal operating ranges for all its units under the Consent Decree. The Authority also paid a $300,000 civil fine and reserved $200,000 to fund certain supplemental environmental projects and programs under the Consent Decree.

Since September 2004, there has been no legal action in the United States federal court or any administrative proceeding against the Authority regarding the Consent Decree or its modification. The Consent Decree includes stipulated penalties for certain events of noncompliance. Noncompliance events must be disclosed to EPA in the corresponding report. Ordinarily, when a covered noncompliance event occurs, the Authority pays the stipulated penalty in advance in order to benefit from a 50% discount of the applicable stipulated penalty provided for under the Consent Order.

The Authority has had some difficulties complying with the emissions and opacity limits in the Consent Decree, as amended, and has occasionally been in violation of other terms of the Consent Decree. From 1999 until 2011, stipulated penalties attributable to noncompliance with the Consent Decree have totaled $2.1 million, of which $1.4 million were related to compliance with the Air Compliance Program and the remainder to compliance with CWA requirements. Based on the 50% discount allowed under the Consent Order (mentioned above), the Authority has in fact paid 50% of the mentioned stipulated penalties. The Authority has devoted great efforts at complying with the Consent Decree and understands that many of the stipulated penalties paid resulted from noncompliance events related to events outside their control, such as equipment malfunctions. As a result, there is no assurance that the Authority will be able to fully comply with the terms of the Consent Decree at all times and eliminate the possibility of paying stipulated penalties in the future.

Another reason compliance with the Consent Decree has been challenging is the requirement that the Authority use low sulfur fuel in some of its power plants. Given that this fuel is more expensive, operational costs have increased significantly. In order to address this challenge, the Authority is planning to restructure its fuel procurement process in order to achieve efficiencies and savings that can result in a lower cost of fuel. The Authority is also planning to convert its generating units to natural gas, a cleaner burning fuel. However, if the Authority is not able to convert its existing units to natural gas (including completing the natural gas delivery infrastructure), it may need to incur in significant capital investments to control emissions in order to comply with the Consent Decree. For more information regarding these initiatives, please see "Fuel Diversification Strategies" under "Plans to Address the Authority's Challenges."

Other Proceedings

In 1997, as a result of an inspection carried out by the EPA and EQB at the Authority's Palo Seco power plant, the EPA issued an Administrative Order (the "RI/FS Order") for the investigation and possible remediation of seven areas identified by the EPA at the Palo Seco power plant and the Palo Seco General Warehouse (Depot). The Administrative Order required the Authority to carry out a Remedial Investigation/Feasibility Study ("RI/FS"). The RI/FS required under the order is designed to: (1) determine the nature and extent of contamination and any threat to the public health, welfare, or environment caused by any release or threatened release of hazardous substances, pollutants, or contaminants at or from the site; and (2) determine and evaluate alternatives for the remediation or control of the release or threatened release of hazardous substances, pollutants or contaminants at or from the site. The RI was completed and submitted to the EPA for evaluation. The Authority was notified by EPA that the FS will not be required and that EPA would issue a "No Action" Record of Decision ("ROD"), with a follow-up review in five years. Public hearings will be scheduled to get public comments on this ROD.

The information gathered in the RI indicated the presence of free product (Separate Phase Hydrocarbons or "SPH") in several monitoring wells. The analysis of this product reflected a low concentration of polychlorinated biphenyls ("PCB"). In 2008, the Authority and the EPA entered into an Administrative Agreement and Order on Consent for a Removal Action (CERCLA 02 2008 2022) (the "AOC") requiring the Authority to provide an enhanced delineation and accurate identification of areas of PCB contamination, implement removal activities to address the PCB-contaminated oil layer and soils and perform confirmatory sampling. The Authority completed the activities of delineation and identification of PCB-containing SPH. By letter dated December 13, 2011, EPA notified the Authority that no further removal action was required at the site and requested that the Authority submit its final removal action report to EPA. The EPA further indicated that, upon receipt of this final report, EPA would issue a site close out letter.

The pending matters to close the RI/FS Order are the issuance of final reports, a public hearing to obtain comments, and the submittal by EPA of a request for reimbursement of costs. The pending matters to close the AOC are the issuance of final reports and the submittal by EPA of a request for reimbursement of costs. The estimated cost to close both orders is $250,000.00. The Authority has not received any requests for reimbursement of costs from the EPA as of this date. However, if it does receive any such requests, the Authority will remit payment to EPA as required by the applicable orders. The Authority believes there are no other matters related to these orders that could potentially result in other enforcement proceedings.

In 2002, the Authority received a "Special Notice Concerning Remedial Investigation/Feasibility Study for Soil at the Vega Baja Solid Waste Disposal Superfund Site." The EPA has identified the Authority and six other entities as "potentially responsible parties," as defined in the CERCLA. In 2003, the Authority agreed to join the other potentially responsible parties in an Administrative Order on Consent ("AOC") for an RI/FS, with the understanding that such agreement did not constitute an acceptance of responsibility. Under the AOC, the Authority committed up to $250,000 as its contribution to partially fund the RI/FS. The Authority and other settling defendants, with the EPA's oversight, completed a RI pertaining to Operating Unit 2 (related to soil contamination) of the site on April 2, 2009, and a FS on July 29, 2010. In April 2004, the EPA issued a ROD determining that no remedial action was required with respect to the groundwater at the site (referred to as Operating Unit 1). In September 2010, the EPA issued a ROD establishing the remedial alternatives to address soil contamination (Operating Unit 2). The Authority and other potentially responsible parties have been negotiating with the EPA and the U.S. Department of Justice ("DOJ") the terms of a settlement agreement covering the responsibilities of the different parties for response actions, including post remedial operations and maintenance, as well as reimbursement of costs incurred by the EPA and DOJ for response actions at the site. The Authority has reached a verbal agreement with EPA to settle this matter by contributing $1.3 million for such efforts to be paid in four yearly payments based on its fiscal years, with the understanding that it is not admitting to any liability. This settlement amount has been authorized by the Authority's Governing Board. In November 2011, EPA and DOJ agreed to send the Authority a draft of the consent order to settle this matter, but the Authority has not received it yet. The final execution of a consent order is subject to final agreement of the parties, including other potentially responsible parties, on the settlement terms. Once this consent order is executed, no additional disbursements are foreseeable, other than the compliance of the parties with the terms of the consent order.

In December 2004, the EPA sent a request for information to the Authority and to other potentially responsible parties that did business with certain recycling companies regarding the release of pollutants by these recycling companies in a Toa Baja superfund site. The EPA has stated that it is particularly interested in entities that disposed of batteries at this site. The Authority has responded to the request for information, stating that it only sold scrap metal to these recycling companies. The Authority does not believe it has any liability regarding this site. In September 2006, EPA issued a Record of Decision determining that the groundwater at the site does not pose an unacceptable risk to the public health or environment and, therefore, no action is required with respect to the groundwater. EPA then continued to investigate potential buried waste and contaminated soil associated with the Site to determine the magnitude and extent of contamination in soil conducted the removal of disposed battery cases, contaminated soil and other debris. According to EPA's Superfund Information Systems website, a combined RI/FS is underway. At this time, we have no knowledge that the EPA has initiated, or intends to initiate, any action against the Authority concerning this matter.

Compliance Programs

The Authority continues to develop and implement a comprehensive program to improve environmental compliance in all applicable environmental media. This program has been and continues to be updated to conform to new regulatory requirements.

Air Quality Compliance

The CAA is a comprehensive federal law that addresses the nation's air quality and the stratospheric ozone layer, and authorizes the EPA to implement and enforce regulations reducing air pollutant emissions. Under the CAA, the EPA is authorized to establish and enforce limits on certain air pollutants from various sources, including utilities. Pursuant to the CAA, the EPA promulgated primary and secondary national ambient air quality standards ("NAAQS") with respect to certain air pollutants, including particulate matter ("PM"), sulfur dioxide ("SO2"), and nitrogen oxide ("NOx"). These standards are to be achieved by the application of control strategies developed by the states (including Puerto Rico) and included in implementation plans which must be approved by EPA to be effective. The Puerto Rico EQB has adopted a State Implementation Plan which was approved by EPA, generally designed to achieve the NAAQS.

The CAA also establishes a permit program (known as the "Title V operating permit program") for large industrial and commercial sources that release pollutants into the air above a specified threshold, known as "major sources." Operating permits include information on which pollutants are being released, how much may be released, and what kinds of steps the source's owner or operator is required to take to reduce pollution. Responsibility for the Title V operating permit program in Puerto Rico was delegated to EQB.

The CAA requires new major stationary sources of air pollution and certain modifications to these sources to obtain an air permit before commencing construction. This permitting process is known as the New Source Review ("NSR"). The NSR program applies to sources that are located in areas that meet the NAAQS (known as "attainment areas"), areas that do not meet the NAAQS (known as "nonattainment areas") and areas that are unclassifiable with respect to the NAAQS. Permits for sources in attainment or unclassifiable areas are issued under the Prevention of Significant Deterioration ("PSD") permit program. The purpose of the PSD program is to prevent the development of new nonattainment areas, among other things.

The Authority's power plants are subject to the Title V operating permit program under the CAA. All of these power plants have their corresponding Title V permits in effect, except for the gas turbine facilities at Yabucoa, Palo Seco, and Mayagüez. The permits for Yabucoa and Mayagüez expired, but the Authority submitted timely renewal applications for both permits, which effectively extended the coverage of these permits during the renewal period. In addition, the Authority submitted a request to modify the Mayagüez permit for the replacement of four old single cycle gas turbine units with four new aero derivative gas turbine units, which request is still being processed by EQB. The permit application for the Palo Seco power plant was filed with EQB in 1996 but the agency has not issued a final permit as of this date. This permit application was filed within the filing term provided for by regulation to activate coverage of the activities covered by the application while the application is in process. Finally, although still within its original effective term, the Authority has also applied for the renewal of the Aguirre power plant's permit in order to ensure extension of coverage under the permit after its expiration date in February 2013.

Generally, the Authority is in compliance with its Title V permits, with the exception of the matters covered by a Consent Decree between EPA and the Authority in 1999, as modified in June 2004,

which continues in effect. Among other things, this Consent Decree covers alleged past noncompliance with opacity requirements and requires the use of fuel oil with sulfur content equal to or less than 0.5% in certain of the Authority's power plants or implement technology that would achieve emissions that would be equivalent to the use of such fuel. The Authority has had some difficulties complying with the emissions and opacity limits in the Consent Decree, as amended, and has occasionally been in violation of other terms of the Consent Decree. For more details on these issues, see "Environmental Litigation and Administrative Proceedings" above.

During fiscal year 2007, the Authority completed projects to reduce NOx emissions at steam electric generating stations at Palo Seco, Aguirre and Costa Sur. As a condition of receiving certain permits, the units at the San Juan plant had previously been modified to reduce NOx emissions. The Authority and EPA monitor compliance with the lower NOx emissions requirements. The Authority is currently in compliance with the NO_X requirements, which are verified by annual testing on units at Costa Sur, Palo Seco and Aguirre.

During the past fiscal year, the Authority reported achieving compliance in excess of 99% with its in-stack opacity requirements and its Air Compliance Program. As required by the Consent Decree's Air Compliance Program, the Authority also submitted and performed all quarterly reports regarding opacity monitors. As of December 2011, when the last quarterly report was submitted, the Authority had achieved a level of compliance with the Air Quality Compliance Program in excess of 99%.

The Authority continues its efforts to use No. 6 fuel oil with a sulfur content equal to or less than 0.5% in all of its power plants, which should contribute to maintaining air quality. Given the high costs associated with the purchase of this fuel and the implementation of the alternative of upgrading air pollution control equipment, continued compliance with this requirement will be very difficult and costly for the Authority. This difficulty is exacerbated by the future requirements to comply with the MATS. Please see "MATS Regulation" below.

In order to address this challenge, the Authority is planning to restructure its fuel procurement process in order to achieve efficiencies and savings that can result in a lower cost of fuel. In addition, the Authority is planning to convert its existing units to natural gas. If the Authority is unable to convert these units to natural gas (including completing the natural gas delivery infrastructure), it may need to incur significant capital investments to control emissions in order to continue to comply with the CAA opacity requirements and the MATS.

MATS Regulation

EPA has issued new regulations related to the requirements of Sections 111 and 112 of the CAA. Section 111 of the CAA requires EPA to set emissions limits for major new stationary sources referred to as New Source Performance Standards or NSPS regulations. Section 112 of the CAA requires the EPA to issue technology-based standards for major sources and certain area sources for hazardous air pollutants ("HAPs"). The categories and subcategories of sources to be regulated under these provisions are listed in Section 112(c) of the CAA. For these sources, the EPA is required to establish emissions standards that require the maximum degree of reduction in emissions of HAPs. These emissions standards are commonly referred to as maximum achievable control technology or MACT standards. Section 112(b) of the CAA contains a list of those pollutants that must be regulated as HAPs pursuant to CAA Section 112, and requires the EPA Administrator to periodically review this list and, where appropriate, revise the list by adding pollutants which present or may present a threat of adverse human health effects or adverse environmental effects.

In 2008, in response to a United States federal court decision and a related consent decree, the EPA decided to regulate coal- and oil-fired electric utility steam generating units, also referred to as EGUs, under Section 112(c) of the CAA. The EPA also subsequently proposed Section 112 air toxic standards for these EGU's that reflect the application of MACT consistent with the requirements of the CAA. This proposal was published in the Federal Register on May 3, 2011 and was signed into a final rule (with minor modifications) on December, 16, 2011.

In connection with the Section 111 standards, on February 27, 2006, EPA promulgated amendments to the NSPS for PM, SO2, and NOx contained in the standards of performance for EGU's. EPA was subsequently sued for these amendments, and on September 2, 2009, was granted a voluntary remand without vacatur of these amendments. The final revisions to these amendments were approved on December 16, 2011, along with the Section 112 air toxic standards discussed above.

On February 16, 2012, EPA published in the Federal Register the final CAA Section 112 rule and the new CAA Section 111 standards. With respect to Section 112, EPA established HAP standards (known as, "National Emission Standards for Hazardous Air Pollutants" or "NESHAP") for coal and oil-fired EGUs to meet standards for toxic air pollutants reflecting the application of the MACT. These standards, known as MATS, are geared at reducing these types of emissions from new and existing coal and oil-fired EGUs. The standards address emissions of mercury, arsenic, chromium, nickel, and acid gases, including hydrochloric acid ("HCl") and hydrofluoric acid ("HF").

The MATS apply to EGU's larger than 25 megawatts that burn coal or oil for the purpose of generating electricity for sale and distribution through the national grid to the public. Existing EGU's generally will have up to four years if they need it to comply with the MATS. This includes the three years provided to all sources by the CAA, and an additional year that may be granted by the EQB, as needed, for technology installation. In essence, the rule establishes: (i) numerical emission limits for mercury, PM, and HCL for all existing coal-fired EGUs; (ii) numerical emission limits for PM, HCL and HF for existing and new oil-fired EGUs, but compliance for HCl and HF may also be achieved by limiting the moisture content of the oil; (iii) alternative numeric emission standards, including SO2 (as an alternate to HCl), individual non-mercury metal air toxics (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM) for certain subcategories of power plants; and (iv) work practices, instead of numerical limits, to limit emissions of organic air toxics, including dioxin/furan, from existing and new coal and oil-fired power plants, which require annual performance test program for each unit to ensure optimal combustion.

As for Section 111, EPA revised the NSPS for fossil-fuel-fired EGU's. This NSPS revised the standards that new coal and oil-fired power plants must meet for PM, SO2, and NOx, by establishing revised numerical emission limits for these. These standards apply to EGUs that burn fossil fuel to produce steam.

The new rule establishing the MATS and the NSPS (which, as mentioned, was published in the Federal Register in February 16, 2012) will become effective on April 16, 2012.

As previously discussed in *New and Future Regulatory Requirements* under RISK FACTORS AND INVESTMENT CONSIDERATIONS, although the Authority is still evaluating the impact of the MATS, it estimates that without a conversion of its oil fired generating capacity to natural gas, it will be required to install MACT on its oil-fired units. The MACT for these units could consist of various retrofitted emission control systems, such as filter baghouses and flue gas desulfurization equipment associated with ancillary systems. The Authority would have until April 2015 to install the MACT, and the capital costs associated with this effort are estimated at $631.6 million to $1.26 billion. Therefore, the Authority believes that in order to comply with the MATS, it will have to convert substantially all of its

existing generating units to burn natural gas instead of fuel oil. If the Authority were not able to convert its existing units to natural gas (including completing the natural gas delivery infrastructure), it would need to make significant capital investments to control emissions in order to comply with the MATS without being able to offset these costs with any cost savings on the purchase of fuel.

GHG Regulations

On April 2, 2007, the U.S. Supreme Court (the "Court") issued a CAA decision in Massachusetts v. Environmental Protection Agency, 549 U.S. 497 (2007) concluding that GHGs meet the CAA definition of an air pollutant and are subject to regulation under the CAA. More specifically, the Court found that the CAA authorizes the EPA to regulate tailpipe greenhouse gas emissions if the EPA determines they cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The Court remanded the case to the EPA to make such an "endangerment determination," which is the statutory prerequisite to authorizing regulations.

In response to the decision, on July 30, 2008, the EPA issued an Advance Notice of Proposed Rulemaking titled "Regulating Greenhouse Gases under the Clean Air Act." This Advance Notice sought comments regarding GHGs regulation under the CAA. The Advance Notice also suggested that the EPA in the future would consider using an existing provision of the CAA to impose energy efficiency standards on electric generating units to reduce greenhouse gases. The comment period closed in November 28, 2008, with parties filing thousands of comments both in favor of and opposed to using the CAA as a tool to address GHGs. Many parties filed comments that supported comprehensive climate change regulation such as cap and trade to address GHGs, but opposed the EPA regulation under the existing CAA due to the unavoidable adverse consequences of using the CAA to regulate GHGs. On April 17, 2009, the EPA, in response to the Massachusetts decision, issued proposed "endangerment" and "cause or contribute" findings for greenhouse gases under Section 202(a) of the CAA. On May 19, 2009, the EPA issued a notice of intent to regulate GHG emissions for cars and trucks under Section 202 of the CAA, following up on the Massachusetts decision discussed above.

On September 15, 2009, the EPA and the Department of Transportation's National Highway Safety Administration proposed a national program to reduce GHG emissions and improve fuel economy for new cars and trucks sold in the United States. On September 30, 2009, the EPA proposed new thresholds for GHG emissions that define when CAA permits under the NSR and Title V operating permits programs would be required. According to the EPA, the proposed thresholds would tailor these permit programs to limit which facilities would be required to obtain permits and would cover nearly 70% of the nation's largest stationary source GHG emitters—including power plants, refineries, and cement production facilities- while shielding small businesses and farms from permitting requirements.

Subsequently, the EPA issued a number of rulemakings and announcements to lay a potential framework for GHG regulation under the CAA and future legislation. On October 30, 2009, the EPA issued a final rule requiring mandatory monitoring in 2010 and reporting of GHGs emissions beginning in 2011 for virtually all industrial source categories across the country. This final rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions. Additionally, the EPA stated that this rulemaking does not indicate that the agency has made any final decisions on pending actions. The EPA stated that the mandatory GHG reporting program will provide the agency, other government agencies, and outside stakeholders with economy-wide data on facility-level (and in some cases corporate-level) GHG emissions, which should assist in future policy development.

On December 7, 2009, the EPA issued the final "endangerment" and "cause or contribute" findings regarding GHGs under Section 202(a) of the CAA. The EPA received several Petitions for

Reconsideration of the Endangerment and Cause or Contribute Findings. Although the findings did not themselves impose any requirements on industry or other entities, this action was a prerequisite to finalizing the EPA's proposed GHGs emission standards for light-duty vehicles, which the EPA proposed in a joint proposal including the Department of Transportation's proposed standards on September 15, 2009. On April 1, 2010, EPA and the Department of Transportation's National Highway Safety Administration issued the first national rule limiting GHG emissions from cars and light trucks. The requirements of this rule took effect on January 2, 2011.

On May 29, 2010, the EPA completed its reconsideration of a memorandum of December 18, 2009, entitled "EPA's interpretation of regulations that determine pollutants covered by the federal PSD program." In this action, the EPA confirmed that any new pollutant that the EPA may regulate becomes covered under the PSD program on the date when the EPA rule regulating that new pollutant takes effect. Accordingly, EPA clarified that the compliance date for GHGs was January 2, 2011 when the rule applicable to mobile sources took effect.

On May 13, 2010, the EPA issued a final rule setting thresholds for GHG emissions that define when permits under the NSR-PSD and Title V operating permit programs are required for new and existing facilities. This final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V operating permits, and is known as the "tailoring rule". Under this rule, the following dates and limits will apply:

1) January 2, 2011 through June 30, 2011: Existing PSD sources undertaking projects that will increase GHG emissions in excess of 75,000 tons per year will be subject to the PSD review for GHGs and would require implementation of the Best Available Control Technology for the emission source. In a similar manner, existing Title V sources will be subjected to Title V requirements for GHGs if a project exceeds 75,000 tons per year of GHGs.

2) July 1, 2011 through June 30, 2013: In addition to step one above, any source that undertakes a new project that exceeds 100,000 tons per year of GHG emissions will be subject to PSD and Title V requirements.

In connection with the EPA rule requiring GHG reporting, on September 2011, the Authority submitted the first report on GHG emissions via electronic submission to EPA. In 2012, the report will be submitted in March 2012 and will include emissions of sulfur hexafluoride from electric power sources.

As for the "tailoring rule," at this moment, the Authority believes that this rule may require it to take measures to reduce GHG emissions, but it is still evaluating the extent of such reductions. One of the alternatives identified to achieve this reduction is the installation of carbon sequestration technology, but this technology does not appear to be feasible for the Authority. In addition, as a result of this rule, the Authority may have to conduct an evaluation of impacts to endangered species, which could potentially require a formal consultation under Section 7 of the Endangered Species Act. The Authority is currently evaluating the extent of this evaluation, if any.

In light of the costs associated with carbon reduction technologies, the Authority believes that the best alternative to achieve lower GHG emissions is to convert its existing units to burn natural gas instead of fuel oil. If the Authority is not able to convert its existing units to natural gas (including completing the natural gas delivery infrastructure), it may need to make significant capital investments to control GHG emissions without being able to offset these costs with any costs savings on the purchase of fuel.

On a related matter, in the spring and summer of 2009 the U.S. House Energy and Commerce Committee advanced a comprehensive climate change bill that would impose economy-wide cap and trade on virtually all industrial sectors, including electricity generation. The Energy and Commerce Committee approved H.R. 2454 on May 21, 2009, and the full House of Representatives passed H.R. 2454 on June 26, 2009. H.R. 2454 would have required existing coal-fired power plants to obtain "allowances" for each ton of GHG emissions, and thus effectively create a "price of carbon." The number of available allowances would have been decreased over future years, increasing the price. It is generally understood that newer facilities that are more energy efficient or which are adaptable to a mix of various conventional and alternative fuels as well as carbon capture and sequestration will be at a competitive advantage in a cap and trade framework compared to less efficient facilities. Further, H.R. 2454 would have preempted much of—but not all of—the EPA's authority to regulate GHG emission from coal-fired power plants under the CAA. Despite the approval of H.R. 2454 by the House, this bill was never passed into law. Although this bill was not enacted into law, the possibility exists that the United States Congress in the future may decide to enact legislation addressing GHGs. At this time, it is not entirely clear what the level of future regulation of these emissions will be, or the costs associated with it.

Water Quality Compliance

The CWA is comprehensive federal law governing water pollution. Section 301 of the CWA prohibits the discharge of pollutants, including thermal discharges, from point sources (which include any discrete conveyances from industrial facilities) into waters of the United States (which includes bodies of water in Puerto Rico), except as authorized under the National Pollutant Discharge Elimination System ("NPDES") permit program. Although EPA may delegate the NPDES permitting authority to states (including Puerto Rico), in Puerto Rico EPA has retained this authority.

With respect to thermal discharges, Section 316(a) of the CWA authorizes EPA to establish effluent limitations for these types of discharges. In addition, Section 316(b) of the CWA requires that NPDES permits for cooling water intake structures ensure that the location, design, construction, and capacity of these structures reflect the best technology available to minimize adverse environmental impacts, which include the impingement and entrainment of fish and egg larvae. As mentioned, impingement refers to the killing of these aquatic organisms by being pinned against intake screens and other parts of the facility, and entrainment refers to the killing of these aquatic organisms by being sucked into the cooling water structures.

The Authority's power plants have discharges associated with their process water systems, cooling water systems and storm water discharges. For these discharges, the Authority's power plants have to comply with NPDES permits under the CWA. The Authority holds NPDES permits under the CWA for all these plants, which are currently in effect (or are under renewal within the applicable regulatory renewal period which affords continued coverage under applicable regulations).

Under the Consent Decree, the Authority was required to abate water pollution at its four major power plants- Aguirre, San Juan, South Coast, and Palo Seco- by implementing certain upgrades and modifications to the discharges of these plants. The Authority has completed the compliance plans for abating water pollution at all of the mentioned plants.

Section 316(a) of the CWA allows EPA to impose alternative effluent limitations for the control of the thermal component of a discharge (in other words, a thermal variance from the otherwise applicable effluent limit). According to EPA regulations, in order to get a thermal variance, a permit holder must demonstrate that the otherwise applicable thermal discharge effluent limit is more stringent than necessary to assure the protection and propagation of the water body's balanced, indigenous

population of shellfish, fish and wildlife. The Authority requested EPA to grant a thermal variance under Section 316(a) for the San Juan power plant's NPDES. The EPA granted this request and incorporated the alternate temperature limit in this plant's NPDES permit, which permit has an effective date on April 1, 2007.

The EPA also included, as a compliance requirement in the San Juan power plant NPDES permit, the performance of thermal plume studies and a biological monitoring program under Section 316(a) of the CWA, and the performance of a Comprehensive Demonstration Study (CDS) under Section 316(b) of the CWA, which requires complying with performance standards for entrainment and impingement at the power plants cooling water intake water structures. On March 13, 2010, the Authority submitted the plans for the thermal plume study and the biological monitoring program to the EPA and is currently awaiting its approval. On March 31, 2008, the Authority submitted an Impingement and Entrainment Characterization Study and Current Status Report for the EPA's evaluation. The Authority also submitted a Post-Repowering Verification Study Work Plan on June 30, 2008. The Authority is waiting for the EPA's approval of such plans in order to perform the thermal plume studies and biological monitoring program. In general, the Authority is up to date in meeting the requirements of this NPDES permit.

With respect to the South Coast power plant, the renewed NPDES permit issued by EPA for this plant in 2009 requires the Authority to construct an outfall discharge pipe offshore so that the thermal discharges can mix with the ocean's cooler waters in the Guayanilla Bay in order to meet temperature water quality standards. The current outfall pipe empties into a cove at the shoreline. The permit requires the Authority to submit progress reports every six months, and to meet a compliance schedule with interim effluent limits and several interim milestones that must be met during the period leading to the construction of the new discharge pipe. The estimated capital cost for this project is approximately $60 million. The Authority is also required to develop a construction mitigation plan to minimize environmental impacts during the construction of the new discharge pipe. The permit further requires that the location design, construction, and capacity of the cooling water intake structure reflects the best technology available to minimize adverse environmental impacts, which includes compliance with impingement and entrainment performance standards to reduce biota mortality, as per Section 316(b) of the CWA. The Authority already performed some operational measures at the South Coast power plant to reduce impingement and entrainment, such as increasing the traveling screens rotation and reducing the screen wash pressure. The Authority is also in the process of designing improvements to the fish return system of the screen wash wastewater discharge.

As per the South Coast plant's NPDES permit, the Authority is required to perform a Detailed Engineering and Environmental Review ("DEER") of alternatives for the cooling water discharge that meets the water temperature standard or otherwise qualifies for a waiver request under Section 316(a) of the CWA. In addition, in accordance with the compliance schedule, the Authority submitted a Draft Environmental Impact Statement ("DEIS") for the cooling water discharge alternatives to the Puerto Rico Permits Management office in October 2011. The DEIS selected the alternative with the least environmental impact, which is the reduction of the cooling water temperature to a range of 96º to 98º by restoring part of the Guayanilla Bay historic flow and improving the Units 5 and 6 condensers. The DEIS will be subject to the comments of federal and local agencies. The estimated capital cost of the selected alternative is approximately $7 million. The completion of these South Coast projects is not expected until fiscal year 2018. In general, the Authority in compliance with the requirements of the compliance plan for this plant.

The Authority submitted to the EPA a Low Impact Demonstration for a Section 316(a) variance for the cooling water discharge at the Palo Seco power plant. The Authority also submitted an Intermittent Flow Application to the EQB under that agency's water quality regulations. Currently, the Authority is negotiating with the EQB and the EPA to include a temperature limit in the water quality

certificate for the cooling water discharge that complies with the Section 316(a) thermal variance requirements.

On February 24, 2011, the EPA issued an Administrative Compliance Order (CWA-02-2010-3119) against the Authority regarding the alleged noncompliance with effluent limitations in the San Juan power plant's NPDES primarily related to nickel, copper, mercury, fecal coliforms and flow parameters. The Administrative Compliance Order required the Authority to submit to the EPA a compliance plan to achieve compliance with the alleged violations and to implement the plan within 180 days. The Authority submitted the required compliance plan and completed all actions required under the plan. Although the Authority has achieved improvements in the compliance record for this plant for fiscal year 2011, certain exceedances of effluent limitations for Outfalls 002 and 003 continue. In order to address this situation, the Authority is currently in a procurement process for the installation of an advanced treatment technology in order to convert the discharges of these outfalls into storm water discharges only. The Authority has informed the EPA of these prospective actions and does not anticipate additional enforcement action related to the Administrative Compliance Order. As of this date, the EPA has not assessed any penalties against the Authority related to this matter. There is no assurance, however, that the EPA will not take additional enforcement action in connection with the exceedances that remain.

As of December 2011, the Authority had achieved a level of compliance with CWA regulations (NPDES permits, Drinking Water Act program, Oil Pollution Act (FRP and operations manual), and SPCC regulations) in excess of 99%.

Proposed Regulation under the CWA

Pursuant to a consent decree with environmental organizations, the EPA has issued past rulemaking under Section 316(b) of the CWA in three phases. In pertinent part, existing large electric-generating facilities were addressed in Phase II rulemaking finalized in February 2004, and existing small electric-generating and all manufacturing facilities were addressed in Phase III rulemaking finalized in June 2006. However, the Phase II rulemaking and a portion of the Phase III rulemaking were subject to a legal challenge and were remanded to EPA for reconsideration. As a result, on April 20, 2011, EPA published a new draft rule pertaining to Section 316(b) of the CWA. Compliance with this rule is established in reference to the date of issuance of the final rule. According to the terms of a settlement agreement, EPA must sign the final rule by July 27, 2012. Therefore, the compliance date with the rule is anticipated to occur at some time after that date.

This new proposed regulation has three components. First, existing facilities that withdraw at least 25 percent of their water from an adjacent water body exclusively for cooling purposes and have a design intake flow of greater than 2 million gallons per day would be subject to an upper limit on how many fish can be killed by impingement. In order to comply with this requirement, the facility is given the option of choosing technologies that would be best suited to address it or reduce its intake velocity to 0.5 feet per second. Second, existing facilities that withdraw very large amounts of water- at least 125 million gallons per day- would be required to conduct studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms sucked into cooling water systems, known as entrainment. Third, new units that add electrical generation capacity at an existing facility would be required to add technology that is equivalent to closed-cycle cooling which may be achieved by incorporating a closed-cycle system into the design of the new unit or making other design changes with equivalent results.

The Authority has a proposal to implement an impingement and entrainment control technology at the South Coast and Palo Seco power plants (aquatic filter barriers), that includes verification sampling for impingement and entrainment. In addition, the Authority is preparing a Plan of Action ("POA") for

the San Juan and South Coast power plants to be submitted to EPA on June 1, 2012. The POA will recommend steps for impingement and entrainment reduction. Based on the steps that have been and will be taken, the Authority understands that it will be able to comply with the proposed rule.

Underground Injection Control Regulation

EPA regulations in 40 C.F.R. Parts 144 to 147 establish requirements governing the protection of ground water. In accordance with these requirements, EPA regulates the construction, operation, permitting, and closure of underground injection control facilities, which are injection wells used to place fluids underground for storage or disposal. This implementation and enforcement of this regulatory program was delegated to the EQB which has issued regulations governing these types of well referred to as underground injection control facilities.

The Authority has septic systems for sanitary discharges for which it does not have underground injection control permits. The Authority prepared a compliance plan to achieve compliance with EQB's underground injection control regulations, which plan was approved by EQB. The compliance plan provides for the closure of 39 septic systems in different power plants, among other things. The schedule of closure is tied to the completion of connections to PRASA's sewer system. As of December 2009, the Authority had completed the connection of sanitary discharges to PRASA's system at the San Juan, Aguirre and Palo Seco power plants. The South Coast power plant's sanitary discharge system was connected to PRASA's system at the beginning of fiscal year 2010. As a result, the Authority is currently engaged in the closing of septic tanks at all of its power plants and is specifically in the process of sampling and analyzing the septic systems at Aguirre, San Juan and Palo Seco. The analysis reports are being sent to EQB for their review and approval prior to beginning closure activities. The Authority understands that it is in compliance with the requirements of the compliance plan approved by EQB.

Spill Prevention Control and Countermeasures Plan

Under the authority of Section 311 of the CWA, EPA has issued regulations setting forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC Plans and establishes procedures, methods and equipment requirements. Some facilities are also required to implement Facility Response Plans ("FRP") depending on the fuel storage capacity and risk of harm to navigable waters and extent of risk they present with respect to an oil spill to a body of water.

Pursuant to the terms of the Consent Decree, the Authority was required to implement a Spill Prevention Maintenance and Construction Program ("SPMCP"). This program included major overhauls to dikes and fuel tanks. As of December 2009, the Authority completed all compliance projects under the SPMCP of the Consent Decree in accordance with the established scope of work.

The Authority has a program to comply with new SPCC requirements that became effective on November 10, 2011, which addressed the containment of potential leakage from oil containing electrical equipment in its distribution substations. The Authority has already implemented the monitoring and inspection requirements under these new regulations (40 C.F.R. §112.7(k)). Notwithstanding the foregoing, during fiscal year 2011, the Authority completed the installation of signage and spill response material at all its substations. In addition, it completed the construction of compliance containment at 21 of the 54 substations that need to be upgraded. The Authority has budgeted $3.5 million for the completion of this program.